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ORIGINAL

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
KRISTIN K. MAYES - Chairman
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. E-04204A-09-0206 ***STAFF'S NOTICE OF FILING SURREBUTTAL TESTIMONY***

Staff of the Arizona Corporation Commission ("Staff") hereby files the Surrebuttal Testimony of Dr. Thomas H. Fish; David C. Parcell; W. Michael Lewis; William C. Stewart; and Kenneth C. Rozen of the Utilities Division.

RESPECTFULLY SUBMITTED this 15th day of January 2010.

Arizona Corporation Commission
DOCKETED
JAN 15 2010
DOCKETED BY

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Original and thirteen (13) copies of the foregoing filed this 15th day of January 2010 with:

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SURREBUTTAL
TESTIMONY
OF

DR. THOMAS H. FISH, Ph.D.

DAVID C. PARCELL

W. MICHAEL LEWIS

WILLIAM C. STEWART

KENNETH C. ROZEN

DOCKET NO. E-04204A-09-0206

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.

JANUARY 15, 2010

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
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SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-04204A-09-0206

SURREBUTTAL

TESTIMONY

OF

THOMAS H. FISH, PH.D.

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JANUARY 15, 2010

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EXECUTIVE SUMMARY
UNS ELECTRIC INC.
DOCKET NO. E-04204A-09-0206

My Surrebuttal Testimony addresses the following issues raised by UNS Electric, Inc. ("UNS Electric" or "Company") witnesses in their Rebuttal Testimony:

- The Company's proposed revenue requirement.
- Adjustments to test year data.
- Rate base
- Test year revenues and expenses

My findings and recommendations for each of these areas are as follows:

- The Company is proposing an increase in gross revenue requirement of $13,500,000 which represents a weighted average cost of capital of 10.38 percent (of which 1.34 percent is fair value adjustment). I identified an operating income deficiency of $4,594,246 and an increase in gross revenue requirement of $7,517,565 in my Direct Testimony. As a result of my analysis and evaluation of the Company's Rebuttal Testimony and information provided by Staff witness Parcell, I am modifying my identified operating income deficiency to $4,631,859 and my recommended increase in gross revenue requirement to $7,579,110 which represents a weighted average cost of capital of 8.4 percent (plus a fair value adjustment of 1.5 percent on the increment in fair value rate base over original cost rate base).

- The following are adjustments to UNS Electric's proposed original cost and fair value rate base from Staff's Direct Testimony and reflecting modifications resulting from Staff's Surrebuttal Testimony:

Summary of Staff Adjustments to Rate Base		**Surrebuttal Testimony Original Cost**	**Direct Testimony Original Cost**	**Surrebuttal Testimony Fair Value**	**Direct Testimony Fair Value**
	Description	Increase (Decrease)	Increase (Decrease)	Increase (Decrease)	Increase (Decrease)
	Remove post test-year plant in service	($7,263,614)	($7,263,614)	($7,263,614)	($7,263,614)
	Cash working capital – lead/lag study	$61,025	($61,025)	$61,025	($61,025)
	Total of Staff Adjustments	($7,202,589)	($7,324,639)	($7,202,589)	($7,324,639)
	UNS Proposed Rate Base	$175,818,913	$175,818,913	$265,152,067	$265,152,067
	Staff Proposed Rate Base	$168,616,324	$168,494,274	$257,949,478	$257,827,428

- The following adjustments to UNS Electric's proposed revenues, expenses and net operating income should be made:

Description	Direct Testimony Increase (Decrease)	Surrebuttal Testimony Increase (Decrease)
Incentive Compensation PEP	($132,159)	($132,159)
Incentive Compensation SERP	($102,142)	($102,142)
Payroll Tax Expense PEP	($10,110)	($10,110)
Call Center Expense	($281,581)	($99,476)
Industry Association Dues	($40,792)	($4,763)
Legal Expense	($58,722)	($27,359)
Fuel Expense	($75,798)	($75,798)
Rate Case Expense	($66,667)	($66,667)
CARES Expense (Revenue Shortfall)	$61,797	$61,797
Bad Debt Expense	($105,487)	$105,487
Depr. & Property tax for Post TY PIS	($442,526)	($442,526)
Income Tax	$481,859	($48,747)
Adjusted Operating Income per UNS Electric	$10,003,347	$10,003,347
Adjusted Operating Income per Staff	$10,899,270	$10,871,910

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Thomas H. Fish. I am President of Ariadair Economics Group. My business address is 1020 Fredericksburg Road, Excelsior Springs, Missouri 64024.

Q. What is the purpose of your Surrebuttal Testimony?

A. The purpose of my Surrebuttal Testimony is to rebut portions of the Rebuttal Testimony of UNS Electric, Inc. ("UNS Electric", "Company" or "UNSE") witnesses Michael J. DeConcini, Dallas J. Dukes, D. Bentley Erdwurm, Kentton C. Grant and Thomas A. McKenna. The areas I will address include rate base/revenue requirement, the Black Mountain Generating Station proposed acquisition treatment, Purchased Power and Fuel Adjustment Clause, and Fuel and Purchased Power Policies.

Q. Did you revise your Schedules as a result of your analysis and review of information provided by the Company in its Rebuttal Testimony?

A. Yes. These Revised Schedules are attached to this Testimony. They are Schedules THF A-1, THF B-1, THF B-2, THF C-1, and THF C-2.

MICHAEL J. DECONCINI

Black Mountain Generating Station ("BMGS")

Q. What does the Company request regarding the Black Mountain Generating Station?

A. The Company requests the Commission to pre-authorize inclusion of the BMGS in rate base after it has been purchased. It proposes a purchase price equal to the total cost net depreciation and a revenue-neutral rate classification that would go into effect only upon acquisition of BMGS by the Company.

Q. In its previous case, did the Company request financing authority to acquire BMGS?

A. Yes. The Company requested and received financing authority to acquire BMGS in its last rate case.

Q. Did the Company acquire the BMGS?

A. No.

Q. Why not?

A. The Company claimed that even with the financing authority it did not have the financial strength to acquire the BMGS.

Q. Are you testifying that the Company should not purchase the BMGS?

A. No. That is a decision to be made by Company management. In fact, as I mentioned in my Direct Testimony, the Commission urged the Company to acquire BMGS. I agree with the Commission's determination in the last case that the Company should pursue purchase of BMGS if it decides that is in the best interest of its customers and owners.

Q. Mr. DeConcini states at page 4 of his Rebuttal Testimony that "Staff argues that the Company chose not to acquire BMGS and that, since it does not own the facility, it should not be included in rate base." Is this a fair statement of Staff's position?

A. To a degree. Staff does not accept that the BMGS should be included in rate base before all facts regarding the purchase are known. After the purchase has been made, then the request for inclusion of BMGS in rate base should be made. At that time, the Commission could be expected to have the necessary facts to make a determination. At this time, prior to the purchase, the Commission may not have all the necessary information. In the last case, in addition to urging the Company to pursue the possible acquisition of BMGS, the Commission was very clear that approval of financing did not imply pre-approval of the purchase. At page 78, lines 23-27, of Decision No. 70360, the Commission stated: "However, approval of the financing set forth herein does not constitute or imply approval or disapproval by the Commission of any particular expenditure of the proceeds derived thereby for purposes of establishing just and reasonable rates."

Q. What reason does the Company provide for requesting pre-approval of inclusion of BMGS in rate base.

A. Company witness DeConcini testified that the Company was unable to buy the BMGS after the last case and acquisition of an asset the size of the BMGS would have a very detrimental impact on the Company's financial position and credit profile.

Q. Does Staff take issue with the Company's determination of the financial impact of the acquisition?

A. Yes. Staff witness Parcell addressed that issue in his Testimony.

Q. At page 5 of his Rebuttal Testimony, Mr. DeConcini lists the benefits of purchasing BMGS. Does Staff disagree with the benefits?

A. Staff has no reason to disagree with Management's determination of the possible benefits of the acquisition. Company management must weigh the benefits and costs of ownership in making its determination to purchase the BMGS or to continue with the Purchased Power agreement regarding BMGS or to pursue other sources of power.

Q. If the Company chooses not to purchase the BMGS, will it lose that source of power?

A. It is my understanding that the purchased power agreement with UniSource Energy Development ("UED") will continue if the Company does not purchase the plant.

CWIP

Q. Does Mr. DeConcini take issue with Staff's recommendation to reject UNS Electric's request to include CWIP in rate base?

A. Yes. Although the Company called the CWIP adjustment "post test-year non-revenue producing plant in service" in Direct Testimony, during the test year it was CWIP. Now Mr. DeConcini is referring to it as "non-revenue post-test year plant" and it was still CWIP during the test year.

Q. Has the Commission addressed inclusion of CWIP in the Company's rate base before?

A. Yes. In the Company's last rate case the Commission rejected both the request to include CWIP in rate base and the request to include Post Test-Year Plant in rate base. In Decision No. 70360, the Commission referred to the Decision in UNS Gas's rate case, Decision No. 70011, where it rejected the Company's requests to include CWIP in rate base, its request to include Post Test-Year Plant in rate base, and its request to not deduct customer advances from rate base.

Q. Do you agree with the Commission's decisions in those two cases?

A. Yes.

Q. Are there situations where including CWIP or Post Test-Year Plant in rate base is necessary and beneficial?

A. In my opinion there are situations where the use of these tools by the Commission is both advisable and beneficial. In my review of past Commission Decisions, it appears that small water companies find themselves in serious financial straits from time to time and the use of these tools has been beneficial in these cases. In other rare situations, other utilities may find themselves in serious financial trouble and require the use of these tools by the Commission. For example, if construction costs of a nuclear generating unit get out of control then the use of CWIP may be useful for maintaining the financial viability of the Utility. In the instant situation, however, I do not believe inclusion of Post Test-Year Plant in rate base is warranted or beneficial.

Purchased Power and Fuel Adjustment Clause ("PPFAC")

Q. Does the Company offer additional reasons for changing the interest rate on PPFAC over- and under-collected balances?

A. Only that the Company will continue to procure fuel and purchased power in a prudent manner if it is allowed to use the 3-month LIBOR rate plus 1 percent as the interest rate on PPFAC over- and under-collected balances.

Q. Does this assurance remove the possible disincentive to strive for a zero bank balance?

A. In my opinion, it does not.

Q. What costs are included in the PPFAC?

A. In Decision No. 70360, the Commission determined that only fuel and purchased power costs recorded in FERC Accounts 501, 547, 555, and 565 should be flowed through the PPFAC. The Commission determined that the recovery of "other" expenses through the PPFAC should be denied.

Q. As part of your analysis in this proceeding, did you review the expense included in the PPFAC?

A. Yes.

Q. Did the Company include expenses other than those allowed by the Commission?

A. I did not identify any non-permissible expenses in the PPFAC as a result of my analysis. In addition, I asked the Company if any non-permissible expenses had been included in the PPFAC and they assured me that none had.

Q. Does the Company incur expenses associated with credit support for its acquisition of wholesale power?

A. Yes.

Q. Did the Company remove those expenses in calculating its revenue requirement?

A. The Company does not offer a pro forma adjustment to remove those expenses from its revenue requirement. They were not included in the PPFAC for recovery.

Fuel and Purchased Power Policies

Q. Mr. DeConcini, at page 11 of his Rebuttal Testimony, suggests that Staff's recommendation to strengthen the relationship between fuel contract management and procurement is related to the acquisition of back-up diesel fuel for the Valencia units. Is this what you were referring to?

A. No. The recommendation is not related to diesel fuel. This recommendation is actually connected to the recommendation for periodic audits on the procurement of fuel and purchased power that I discuss on page 63 of my Direct Testimony. My review of the Company's data request responses and my visit with Company personnel in Tucson regarding the prudence of PPFAC procedures and policies indicate to me that the Company's PPFAC policies and procedures are, overall, well organized and efficient. There does appear, however, to be somewhat of a disconnect between the identification and acquisition process of a source of purchased power and the actual procurement of the power within the framework of each contract. In my opinion, although I did not identify specific problems as a result of my analysis, a periodic connection of the procurement process and the source agreement could strengthen this area. Also, as Mr. DeConcini noted in response to Staff data request STF 3.135, the Company had no audit reports issued in 2007 or 2008 related to the procurement of fuel and purchased power. Therefore, periodic audits of this relationship could serve to further strengthen this area.

Q. Mr. DeConcini, at page 12 of his Rebuttal Testimony, states that the Company does not have any interstate pipeline capacity and implies that all gas procurement for the Company is by UNS Gas. Do you agree?

A. UNS Electric does not have interstate pipeline capacity and, as I discussed in my Direct Testimony, UNS Gas provides natural gas to the Company. However, the Company does hedge gas, and it does this with the use of financial swing products because the actual physical gas is supplied by UNS Gas. When hedging, UNS Electric is hedging price risk through the use of fixed price financial swing gas.

Q. Are there characteristics of the months of August, September, and October which make them especially important in hedging operations involving natural gas?

A. Yes. Those months represent the hurricane season. Hurricanes in the Gulf of Mexico disrupt the production of natural gas and can result in significant price swings. This extra risk translates into extra hedging costs. During my visit to Tucson, UNS Electric personnel expressed concern regarding the implication of the UNS Gas case for additional hedging costs if hedging is required to be undertaken during these months. Their position was that situations could arise where the cost and risk relationships were such that hedging during these months would be beneficial but there could also be situations where hedging would not be beneficial. In light of this expressed concern, and I consider it a legitimate concern, I made the recommendation to consider hedging, rather than require it, during these months.

DALLAS J. DUKES

CWIP

Q. Did Company witness Dukes address your position regarding Post Test-Year Plant in Service in his Rebuttal Testimony?

A. Yes. At page 8 of his Rebuttal Testimony, Mr. Dukes states that Staff's position is wrong. His reasoning is essentially the same as presented by Mr. DeConcini. However, Mr. Dukes includes a discussion of previous Commission Decisions which he believes support the Company's request.

Q. Do you agree with Mr. Dukes' analysis?

A. No. I disagree with Mr. Dukes' analysis for the same reasons given above in my response to Mr. Deconcini's discussion of this issue. With respect to the previous Decisions referred to by Mr. Dukes, it is my understanding that the Commission evaluates each case on its own merits, and the facts of the cases of these water companies are different than in the instant case. I addressed these cases in my Direct Testimony.

Working Capital

Q. Did you propose a pro forma adjustment with respect to the Company's working capital?

A. I proposed two adjustments. First, since Staff's pro forma adjustments were different than the Company's pro forma adjustment, an adjustment for this difference was required. Second, the Company made an error in its calculations as identified in footnote 3 of my Direct Testimony.

Q. What was the result of the two adjustments?

A. The result was to increase rate base by $61,025.

Operating Income Adjustments

Incentive Compensation Expense

Q. Did Mr. Dukes disagree with your pro forma adjustment for Performance Enhancement Plan ("PEP") cost?

A. Yes. First, he suggested that the PEP expense Staff used was incorrect because it was taken from the Company's Federal Energy Regulatory Commission ("FERC") Form 1. He stated that FERC Form 1 overstated PEP expenses and that Staff should have used a smaller PEP value. He did not, however, provide any meaningful evidence that the FERC Form 1 expense was incorrect and that the Company was preparing a corrected FERC Form 1. If he makes this revision to FERC Form 1, Staff would consider using the smaller PEP value in its analysis.

Second, Mr. Dukes argues that the fact that incentive pay benefits both owners and ratepayers is no reason for owners to share the cost of the program with ratepayers. He then compares incentive pay to payroll expense. Incentive pay, of course, is distinctively different compared to payroll expense. Incentive pay is earned over and above base pay, and its purpose is to induce greater efficiency and productivity from employees than payroll expense alone. This extra reward for above normal productivity makes this cost unique and subject to separate treatment. Normal payroll expenses are a normal and ongoing cost of providing service. Incentive pay is designed as a reward for extraordinary and above normal service and benefit to the Company and as such its cost should be borne by the parties that enjoy the above normal service and benefit, the Company's owners and ratepayers.

Q. Does Mr. Dukes agree with your proposed pro forma adjustment to remove Supplemental Executive Retirement Plan ("SERP") expenses?

A. No. The SERP program is an incentive program for UniSource officers that exceeds Internal Revenue Service retirement guidelines. Staff does not argue that the program be eliminated only that the cost not be recovered from ratepayers.

Q. What is the basis for Mr. Dukes' position?

A. First, that it is not fair for one group of employees to receive retirement pay that is funded in rates and not for another group of employees to receive the same treatment. Second, he states at page 21, lines 19-20, that "It (SERP) simply keeps those individuals whose compensation level exceeds deductibility levels equal to those individuals whose compensation does not." Apparently Mr. Dukes believes that employees whose compensation levels are $40,000 per year are equal in compensation to employees whose compensation levels exceed $750,000 per year.

Q. Do you agree with Mr. Dukes' arguments?

A. No.

Rate Case Expense

Q. Did Mr. Dukes agree with your proposal to limit the Company's rate case expense to $100,000 per year?

A. No. Mr. Dukes argues that the Company's actual rate case expense is higher than comparable Company expenses because the Company must compensate Tucson Electric Power Company ("TEP") for the use of TEP personnel, there is a significant amount of discovery, and numerous internal personnel, outside counsel and consultants are required. In addition, because of the variety of issues involved, it does not make sense to develop its own rate case team.

Q. Do you agree with Mr. Dukes' arguments to recover extra rate case expense?

A. No. Mr. Dukes offers no additional justification for increasing rate case expense.

Membership Dues Expense

Q. Did the Company incur membership dues for Edison Electric Institute ("EEI")?

A. In its work papers supporting its pro forma adjustment, the Company provides a copy of an invoice in the amount of $125,029 from EEI dated 12/12/07 for the year 2008 sent to TEP. This invoice was paid quarterly. Another invoice was sent to TEP from EEI on 12/12/07 for regular activities for the year 2008 in the amount of $314,244. Another was sent to TEP from EEI dated 4/2/08 in the amount of $28,000. No invoices for membership dues were sent to UNSE from EEI.

Q. Did UNS Electric pay membership dues to EEI?

A. A memo from Sharon Feltz to Mina Briggs was provided by the Company dated 3/2/08. Ms. Feltz asked whether UNSE should have been charged a part of the regular $314,244 member dues. Ms. Briggs replied that UNS Electric should have been charged $10,000. In its work papers, the Company says that it paid a total of $12,000 EEI dues and removed $1,628 of those in its pro forma adjustment, leaving a total of $11,172 of EEI dues in revenue requirement. However, there is no record of payment by UNSE of the $12,000 in the work papers, there is no record of an invoice from EEI to UNSE for membership dues in the work papers, and there is no record of membership of UNSE in EEI in the work papers.

Q. Did the Company incur this expense during the test year?

A. No. The Company made a posting error, and the amount was not included in revenue requirement for the test year.

Q. Did UNSE receive an invoice from EEI for EEI membership dues?

A. There is no record in the work papers that UNSE received an invoice from EEI for EEI membership dues as a member of EEI.

Q. If the Company is not a member of EEI and is not entitled to the benefits of membership should it be paying EEI dues?

A. No.

Q. Have you revised your adjustment for Industry Association Dues?

A. Yes. I have reduced my adjustment for Industry Association Dues from $40,792 to $4,763 as shown on page 1 of Schedule THF C-2.

Call Center Expense

Q. Company witness Dukes alleges that Staff used an incorrect amount for 2006 test year Call Center expenses in making your Call Center pro forma adjustment. Did you use an incorrect amount?

A. No. Staff used the Call Center information pointed to by the Company. In its response to Staff data request STF 5.3, the Company stated that calendar year 2006 information had been provided in the last case and it saw no reason to provide that same information in this case. The available information the Company referred to was the information Staff used in its adjustment. The data referred to by Mr. Dukes were not provided until the Company filed its Rebuttal Testimony.

Q. Were the data recently provided by the Company more relevant than the information you originally relied on?

A. Yes.

Q. Did this more recent data affect your proposed pro forma adjustment?

A. Yes. I used the more recent data in my proposed pro forma adjustment. I have reduced my adjustment for Call Center Expense from $281,581 to $99,476. This modification is reflected in the attached Schedules.

Bad Debt Expense

Q. Did the Company err in the calculation of its bad debt expense?

A. Yes.

Q. What was the error the Company made in deriving its bad debt expense?

A. It understated its bad debt expense by $105,487.

Q. How was the Company able to understate its bad debt expense by $105,487?

A. Company Schedule C-2 page 3 of 4 shows a bad debt expense pro forma adjustment of $436,441 and the page total includes this amount. The actual bad debt expense for the test year was about $1.2 million. The Company normalized the bad debt expense by calculating the average bad debt ratio to gross revenue for the years 2006, 2007, and 2008. The Company then multiplied that ratio by test year adjusted retail revenues rather than gross revenue. The three-year bad debt ratio should have been multiplied by gross retail revenues and that value subtracted from actual bad debt expense to derive the normalized bad debt pro forma adjustment.

Q. Have you revised your adjustment for Bad Debt Expense?

A. Yes. I have reversed my $105,487 adjustment for Bad Debt Expense as shown on page 2 of Schedule THF C-2.

Outside Legal Expense

Q. Did Company witness Dukes address your outside legal expense pro forma adjustment in his Rebuttal Testimony?

A. Yes.

Q. Did Mr. Dukes express concern regarding your selection of years in the three-year average outside legal expense values you used?

A. Yes. In his proposed pro forma adjustment, Mr. Dukes used the 2005, 2006 and 2007 adjusted outside legal expense values in his calculations. I used the 2005, 2006 and 2008 outside legal expense values in my calculations because the 2007 outside legal expense is an outlier compared to the other years and would have a biasing effect on the result.

Q. What were the three-year average outside legal expense values?

A. The three-year average outside legal expense value calculated by the Company was $138,263.69 and the three-year average outside legal expense value calculated by Staff was $87,552.94, shown in Schedule THF C-8 in my Direct Testimony. These average values, when compared to the test year amount resulted in a pro forma adjustment by Mr. Dukes of $109,433.80 and by Staff of $58,722. Therefore, Staff's adjustment to the proposed Company pro forma adjustment is a reduction of the difference, or $50,962.

Q. In your opinion, what is the reason for the difference in the value of the pro forma outside legal expense adjustment?

A. In my opinion, the difference is due to the selection of the years to use for normalization. The 2007 adjusted value is the highest of the four years, 2005 through 2008, and the adjusted 2008 value is the smallest. The Company chose the highest value, and Staff chose the smallest value.

Q. Is there another normalization technique that the Commission could consider?

A. Yes. For normalization purposes a three-year period is frequently used. In this situation, however, because of the extreme values, I recommend that the Commission consider a four-year normalization period that includes all values 2005 through 2008. In this way, the two extreme values might be expected to cancel each other out and result in a more representative value.

Q. Did you make that four-year calculation?

A. Yes. The attached Schedules include a recommended pro forma adjustment based on a four-year normalization period, 2005 through 2008, for outside legal expenses. I have reduced my adjustment for Legal Expense from $58,722 to $27,359.

Fleet Fuel Expense

Q. Did the Company propose an adjustment to its fleet fuel expense?

A. Not in its original filing. However, in the Rebuttal Testimony of Mr. Dukes, the Company agreed to normalize fleet fuel expense over three years.

Q. In your opinion, is this new proposal by the Company appropriate?

A. In my opinion, the change recommended by the Company is much better and more indicative of ongoing fleet fuel expense that the test year values. The fuel costs for the test year were at a historic high and have not continued at that level. Therefore, although the Company's new proposed test year fuel expense is better than the Company's original proposal, it is biased by including the extreme test year value. Staff's proposal is much more indicative of reasonably expected ongoing fleet fuel expenses.

D. BENTLEY ERDWURM

Q. Did you propose a pro forma adjustment to remove the Company's proposed pro forma increase in test year revenue related to Customer Assistance Residential Energy Support ("CARES") customers?

A. Yes.

Q. Does the Company disagree with your proposed CARES pro forma revenue adjustment?

A. Yes. In his Rebuttal Testimony, Company witness Erdwurm argues that the Company's proposed pro forma adjustment of $61,797 is necessary for the Company to recover its revenue requirement.

Q. What is the basis for the Company's disagreement with your pro forma CARES revenue adjustment?

A. Company witness Erdwurm, at page 13 of his Rebuttal Testimony, states that the Company did not correctly calculate CARES customer annualization and CARES weather normalization so the adjustment is necessary to correct for that error.

Q. Did Mr. Erdwurm provide any support that the annualization and normalization mistakes amounted to a cost of $61,797?

A. No.

Q. Do you agree that Mr. Erdwurm's calculation error resulted in a $61,797 understatement of revenue?

A. No. There does not appear to be any support to this guess.

KENTTON C. GRANT

BMGS

Q. What position does Company witness Grant take with respect to your recommendation for the Commission to not accept the Company's BMGS request?

A. Mr. Grant states that the Company cannot finance BMGS without some assurance from the Commission for timely rate relief. He goes on to point out that the Company does not have sufficient cash flow, even with its requested rate relief, to service the additional capital required to purchase the BMGS.

Q. Will the proposed rate restructuring change its cash flow?

A. My understanding is that the rate restructuring will be revenue neutral. Therefore, the total cash flowing into the Company from its retail operations will be the same in either case. The use of that cash will be different. Acquisition of the BMGS could be expected to increase cash used for servicing the capital required for the acquisition and reduce cash expended under the BMGS Purchased Power agreement. However, if revenue neutrality is to be maintained, total cash in and out should not be affected.

Q. Is the Company asking for additional rate relief upon its proposed acquisition of BMGS?

A. Mr. Grant seems to be implying that the Company will seek additional rate relief upon acquisition of BMGS. Company witnesses, including Mr. Grant, have stated that the acquisition of BMGS is revenue neutral. That is, they claim that upon acquisition of BMGS the Company would restructure their rates but that the revenue impact from either the current or restructured rates would be the same.

PPFAC

Q. Does Mr. Grant offer reasons to recover wholesale credit costs in the PPFAC?

A. Yes. First, he proposes, at page 27 of his Rebuttal Testimony, that these costs are directly related to the fuel and wholesale power procurement function. Second, the level of credit support will vary depending upon the size of the Company's payable balances and the market value of forward energy purchases committed to by the Company.

Q. In your opinion, are these reasons sufficient justification to include wholesale credit costs in PPFAC?

A. No.

Q. Has the Commission demonstrated a pattern of allowing other costs in the PPFAC?

A. No. It is my understanding that the Commission has not done so. In Decision No. 69663, Arizona Public Service was not permitted to include broker's fees in its PSA and in Decision No. 70360 UNSE was not permitted to include other costs such as broker's fees, credit costs, and legal fees in its PPFAC.

Fair Value Rate of Return

Q. Did Company witness Grant indicate that Staff understated its proposed revenue requirement?

A. Yes. At page 12 and 13 of his Rebuttal Testimony Company witness Grant stated that a mathematical error was made that resulted in Staff understating the Company's revenue requirement by $633,000.

Q. What did Mr. Grant cite as the cause of the error?

A. Mr. Grant stated that there was a typographical error in Mr. Parcell's testimony which suggested a fair value rate of return of 5.99 percent rather than 6.14 percent caused the alleged revenue understatement.

Q. Did a possible typographical error in Mr. Parcell's testimony result in an underestimate of Staff's determination of the Company's revenue requirement?

A. No.

Q. What was the basis for the Company's determination that an error associated with the FVROR had caused the understatement of Staff's determination of UNSE's gross revenue requirement?

A. It is my understanding that the basis was a typo in a table at page 57 of Mr. Parcell's Direct Testimony. The table, as it appeared, was:

Capital Item	Percent	Cost	Return
Long-Term Debt	36.45%	7.05%	2.57%
Common Equity	30.76%	10.00%	3.08%
FVRB Increment	32.79%	1.50%	0.34%
Total	100.00%		5.99%

The highlighted return on Fair Value Rate Base ("FVRB") Increment of 0.34 percent is a typographical mistake that resulted in a (highlighted) total return of 5.99 percent. The correct value is shown as:

Capital Item	Percent	Cost	Return
Long-Term Debt	36.45%	7.05%	2.57%
Common Equity	30.76%	10.00%	3.08%
FVRB Increment	32.79%	1.50%	0.49%
Total	100.00%		6.14%

Mr. Grant multiplied the difference in total return (0.15 percent) times FVRB and determined that an addition to gross revenue requirement of $633,000 was required. This conclusion is not correct.

Q. Why isn't Mr. Grant's analysis and conclusion correct?

A. Mr. Parcell was addressing the Company's capital cost and its capital structure. Consider the following table based on the table on page 57 of Mr. Parcell's Direct Testimony:

Capital Item	Percent	Dollar Amount	Cost	Return
Long-Term Debt	36.45%	$93,978,098	7.05%	2.57%
Common Equity	30.76%	$79,307,717	10.00%	3.08%
FVRB Increment	32.79%	$84,541,634	1.50%	0.49%
Total	100.00%	$257,827,428		6.14%

Note that the dollar amount for FVRB Increment calculated on the basis of the information in the table is $84,541,634. The actual increment of FVRB over Original Cost Rate Base, from Schedule THF A-1, is $89,333,154. Therefore, the correct percent for the FVRB Increment is $89,333,154/257,827,428 = 34.65 percent. Mr. Parcell's table was based on the Company's capital structure which understated the 1.5 percent component by about $5m and overstated the 8.4 percent debt and equity components by the same amount. The result was an illusionary overstatement of FVROR by .15 percent.

Using the proper rate base values results in the following FVROR:

	Dollar		Dollar	
Capital Item	Amount	Cost	Cost	Return
Debt & Equity	$168,494,273	8.40%	$14,153,519	5.49%
FVRB Increment	$89,333,154	1.50%	$ 1,339,997	0.52%
Total	$257,827,428		$15,493,516	6.01%

Q. What do you conclude with respect of your review of Mr. Grant's criticism of your gross revenue requirement?

A. There is no understatement of the Company's gross revenue requirement as determined by Staff. My determination of the Company's gross revenue requirement and its return on fair value rate base is consistent with Mr. Parcell's cost of capital analysis. Mr. Grant simply erred in confusing capital structure with rate base.

Q. Why did you use values from Staff's Direct Testimony in your analysis above rather than your revised Surrebuttal values?

A. For consistency purposes. The use of the Direct Testimony values allows for proper comparison of the numbers used by Mr. Grant, Mr. Parcell, and myself. The conclusion is valid for both the Direct and Surrebuttal situations, i.e., there is no inconsistency between Mr. Parcell's and my analyses in our Direct or Surrebuttal Testimonies.

THOMAS A. MCKENNA

Q. Does Company witness McKenna address your recommendation regarding UNSE's proposed acquisition and treatment of the BMGS?

A. Yes.

Q. Does Mr. McKenna offer additional reasons why the Company should be authorized to use its proposed rate base and ratemaking treatment of BMGS?

A. No. Mr. McKenna simply restates the position of the Company with respect to this issue.

Q. Do you have additional comments regarding this issue?

A. No. The comments I offered above are relevant to Mr. McKenna's proposed justification for implementation of the Company's proposal.

Q. Would you summarize your conclusions with respect to your determination of the Company's operating income deficiency and change in gross revenue requirement?

A. I identified an operating income deficiency of $4,594,246 and an increase in gross revenue requirement of $7,517,565 in my Direct Testimony. As a result of my analysis and evaluation of the Company's Rebuttal Testimony and information provided by Staff witness Parcell, I am modifying my identified operating income deficiency to $4,631,859 and my recommended increase in gross revenue requirement to $7,579,110 which represents a weighted average cost of capital of 8.4 percent (plus a fair value adjustment of 1.50 percent on the increment in fair value rate base over original cost rate base).

Q. Does that conclude your testimony?

A. Yes.

UNS Electric, Inc.
Docket No. E-04204A-09-0206-Fish Surrebutal
Computation of Increase in Gross Revenue Requirements
Test Year Ended December 31, 2008

Line No.	Description	(a) Company Original Cost	(b) Staff Original Cost	(c) Company RCND	(d) Staff RCND	(e) Company Fair Value	(f) Staff Fair Value	Line No.
1	Adjusted Rate Base	$175,818,913	$168,616,324	$354,485,222	$347,282,633	$265,152,067	$257,949,478	1
2	Adjusted Operating Income	$10,003,347	$10,871,910	$10,003,347	$10,871,910	$10,003,347	$10,871,910	2
3	Current Rate of Return (2/1)	5.69%	6.45%	2.82%	3.13%	3.77%	4.21%	3
4	Required Operating Income	$18,253,668	$14,163,771	$18,253,668	$14,163,771	$18,253,668	$14,163,771	4
	Plus Fair Value (Line 6)		$15,503,769		$14,163,771		$15,503,769	
5	Weighted Average Cost of Capital	9.04%	8.40%	5.15%	4.08%	6.88%	6.01%	5
6	Fair Value Adjustment*	1.34%	$1,339,997		$0			6
7	Required Rate of Return	10.38%		5.15%		6.88%		7
8	Operating Income Deficiency	$8,250,321	$4,631,859	$8,250,321	$3,291,861	$8,250,321	$4,631,859	8
9	Gross Revenue Conversion Factor	1.6363	1.6363	1.6363	1.6363	1.6363	1.6363	9
10	Increase in Gross Revenue Requirement	$13,500,000	$7,579,110	$13,500,000	$5,386,472	$13,500,000	$7,579,110	10

Supporting Schedules
Columns (a), (c), and (e) Company Schedule A-1
Line 1, columes b, d, & f From Staff Schedule THF B-1
Line 2, columes b, d, & f From Staff Schedule THF C-1
*Staff fair value adjustment is equal to Staff witness Parcell Fair Value return midpoint (0% - 3%, or 1.5%) x difference between fair value and original cost rate base.

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Original Cost and Adjusted RCND Rate Base-Fish Surrebuttal
Test Year Ended December 31, 2008

Line No.	Description	(a) Company Adjusted Original Cost Rate Base	(b) OCRB Staff Adjustments	(c) OCRB as Adjusted by Staff	(d) Company RCND	(e)* RCND Staff Adjustments	(f) RCND as Adjusted by Staff	(g)** Company Fair Value Rate Base	(h)** Staff Fair Value Rate Base	Line No.
1	Gross Utility Plant in Service	$454,177,170	$7,263,614	$446,913,556	$844,301,155	$7,263,614	$837,037,541	$649,239,162	$641,975,548 $0	1
2	Less: Accumulated Depreciation	193,348,359	0	$193,348,359	$367,590,759	$0	$367,590,759	$280,469,559	$280,469,559	2
3	Net Utility Plant in Service	260,828,810	7,263,614	$253,565,196	$476,710,396	$7,263,614	$469,446,782	$368,769,603	$361,505,989	3
4	Citizens Acquisition Discount	(93,273,341)	0	($93,273,341)	($130,469,005)	$0	($130,469,005)	($111,871,173)	($111,871,173)	4
5	Less: Accum. Amort. - Citizens Acq. Discount	(20,876,317)	0	($20,876,317)	($27,773,948)	$0	($27,773,948)	($24,325,132)	($24,325,132)	5
6	Net Citizens Acquisition Discount	(72,397,024)	0	($72,397,024)	($102,695,057)	$0	($102,695,057)	($87,546,041)	($87,546,041)	6
7	Total Net Utility Plant	188,431,786	7,263,614	$181,168,172	$374,015,339	$7,263,614	$366,751,725	$281,223,563	$273,959,949 $0	7
8	Customer Advances for Construction	(12,605,744)	0	($12,605,744)	($17,555,056)	$0	($17,555,056)	($15,080,400)	($15,080,400)	8
9	Customer Deposits	(4,064,671)	0	($4,064,671)	($4,064,671)	$0	($4,064,671)	($4,064,671)	($4,064,671)	9
10	Accumulated Deferred Income Taxes	(2,028,227)	0	($2,028,227)	($3,996,158)	$0	($3,996,158)	($3,012,192)	($3,012,192)	10
11	Total Deductions	(18,698,641)	0	($18,698,641)	($25,615,885)	$0	($25,615,885)	($22,157,263)	($22,157,263)	11
12	Allowance for Working Capital	6,085,768	(61,025)	$6,146,793	$6,085,768	($61,025)	$6,146,793	$6,085,768	$6,146,793	12
13	Regulatory Assets	0	0	$0	0	0	0	0	0	13
14	Regulatory Liabilities	0	0	0	0	0	0	0	0 0	14
15	Total Rate Base	$175,818,913	$7,202,589	$168,616,324	$354,485,222	$7,202,589	$347,282,633	$265,152,067	$257,949,478	15

Supporting Schedules
Column A and D from Company filing
Column B and E from THF B-2
*For Column (e) test year OCRB and RCND adjustments have the same value for Post test year PIS and Working Capital so no separate THF B-2 equivalent Schedule is required for RCND
**Fair Value rate base, columns (g) and (h) are derived as an average of OCRB and RCND

UNS Electric, Inc.
Docket No. E-04204A-09-0206-Fish Surrebuttal
Pro Forma Adjustments to Original Cost Rate Base
Test Year Ended December 31, 2008

Line No.	Description	(a) Company Actual End of TY	(b) Staff Adjustments (a)	(c) Staff Adjusted at End of TY	Line No.
1	Gross Utility Plant in Service	$454,177,170	$7,263,614	$446,913,556	1
2	Less: Accumulated Depreciation	193,348,359	0	193,348,359	2
3	Net Utility Plant in Service	260,828,811	7,263,614	253,565,197	3
4	Citizens Acquisition Discount	(93,273,341)	0	(93,273,341)	4
5	Less: Accum. Amort. - Citizens Acq. Discount	(20,876,317)	0	(20,876,317)	5
6	Net Citizens Acquisition Discount	(72,397,024)	0	(72,397,024)	6
7	Total Net Utility Plant	188,431,787	7,263,614	181,168,173	7
8	Customer Advances for Construction	(12,605,744)	0	(12,605,744)	8
9	Customer Deposits	(4,064,671)	0	(4,064,671)	9
10	Accumulated Deferred Income Taxes	(2,028,227)	0	(2,028,227)	10
11	Total Deductions	(18,698,642)	0	(18,698,642)	11
12	Allowance for Working Capital	6,085,768	(61,025)	6,146,793	12
13	Regulatory Assets	0	0	0	13
14	Regulatory Liabilities	0	0	0	14
15	Total Original Cost Rate Base	$175,818,913	$7,202,589	$168,616,324	15

Supporting Schedules
(a) B-2,Pg. 2

Recap Schedules
B-1

UNS Electric, Inc.
Docket No. E-04204A-09-0206-Fish Surrebutal
Pro Forma Adjustments to Original Cost Rate Base
Test Year Ended December 31, 2008

Line No.	Description	Post-Test Year Non-Revenue Plant in Service	Working Capital	Total Page Adjustments	Line No.
1	Gross Utility Plant in Service	$7,263,614		$7,263,614	1
2	Less: Accumulated Depreciation				2
3	Net Utility Plant in Service	7,263,614		7,263,614	3
4	Citizens Acquisition Discount				4
5	Less: Accum. Amort. - Citizens Acq. Discount				5
6	Net Citizens Acquisition Discount				6
7	Total Net Utility Plant	7,263,614		7,263,614	7
8	Customer Advances for Construction				8
9	Customer Deposits				9
10	Accumulated Deferred Income Taxes				10
11	Total Deductions				11
12	Allowance for Working Capital		$61,025	61,025	12
13	Regulatory Assets				13
14	Regulatory Liabilities				14
15	Total Original Cost Rate Base	$7,263,614	$61,025	$7,324,639	15

Supporting Schedules
B3, B4

UNS Electric, Inc.-Fish Surrebuttal
Docket No. E-04204A-09-0206-Fish Surrebutal
Adjusted Test Year Income Statement
Test Year Ended December 31, 2008

Line No.	Description	Company Unadjusted (a)		Company Pro Forma Adjustments (b)	Company	Staff Adjustments	Staff Adjusted	Line No.
	Operating Revenues							
1	Electric Retail Revenues	$181,638,915		($22,358,469)	$159,280,446	$61,797	$159,342,243	1
2	Sales for Resale	10,168,115		(10,168,115)	0	0	0	2
3	Other Operating Revenue	3,103,658		(1,458,039)	1,645,619	0	1,645,619	3
4	Total Operating Revenues	194,910,688		(33,984,623)	160,926,065	61,797	160,987,862	4
	Operating Expenses							
5	Fuel, Purchased Power & Transmission	143,362,723		(32,059,158)	111,303,565	0	111,303,565	5
6	Other Operations and Maintenance Expense	21,569,849	(1)	(2,144,234)	19,425,615	(412,987)	19,012,628	6
7	Depreciation and Amortization	14,429,415		(194,193)	14,235,222	0	14,235,222	7
8	Taxes Other than Income Taxes	3,680,634		156,415	3,837,049	(442,526)	3,394,523	8
9	Income Taxes	2,081,685		39,582	2,121,267	48,747	2,170,014	9
10	Total Operating Expenses	185,124,306		(34,201,588)	150,922,718	(806,766)	150,115,952	10
11	Operating Income	9,786,382		$216,965	$10,003,347	$868,563	$10,871,910	11
	Other Income and Deductions							
12	Allowance for Equity Funds	322,168						
13	Other - Net	76,881						
14	Total Other Income and Dedu	399,049						
15	Income Before Interest Expense	10,185,431						
	Interest Expense							
16	Interest on Long-Term Debt	6,546,248						
17	Other Interest Expense	57,412	(1)					
18	Allowance for Borrowed Funds	(181,815)						
19	Total Interest Expense	6,421,845						
20	Net Income Available for Common Stock	$3,763,586						

(1) Includes reclasification of $160,200 for Customer Deposit Interest Expense From Other Interest Expense to Other O&M Expense.

UNS Electric, Inc.
Docket No. E-04204A-09-0206-Fish Surrebutal
Income Statement Pro Forma Adjustments
Test Year Ended December 31, 2008

Line No.	Description	Incentive Compensation Adj PEP	Incentive Compensation Adj SERP	Payroll Tax Expense, PEP incentive	Call Center Expense Adj	Industry Association Dues	Legal Expense	Total Page Adjustments
	Operating Revenues							
1	Electric Retail Revenues	$0	$0	$0	$0	$0	$0	$0
2	Sales for Resale	0	0	0	0	0	0	0
3	Other Operating Revenue	0	0	0	0	0	0	0
4	Total Operating Revenues	0	0	0	0	0	0	0
	Operating Expenses							
5	Fuel, Purchased Power & Transmission	0	0	0	0	0	0	0
6	Other Operations and Maintenance Expense	132,159	102,142	10,110	99,476	4,763	27,359	376,009
7	Depreciation and Amortization	0	0	0	0	0	0	0
8	Taxes Other than Income Taxes	0	0	0	0	0	0	0
9	Income Taxes	0	0	0	0	0	0	0
10	Total Operating Expenses	132,159	102,142	10,110	99,476	4,763	27,359	376,009
11	Operating Income	($132,159)	($102,142)	($10,110)	($99,476)	($4,763)	($27,359)	($376,009)

1
Docket No. E-04204A-09-0206-Fish Surrebutal
Income Statement Pro Forma Adjustments
Test Year Ended December 31, 2008

Line No.	Description	Fuel Expense Adjustment	Rate Case Expense	C.A.R.E.S. Expense	B ad Debt Expense	Depreciation and Property Tax for Post TY Non-Rev Plant in Service	Normalized Income Tax Corrected*	Normalized Income Tax for pro forma adjstment corrections**	Total Page Adjustments	Total Adjustment
	Operating Revenues									
1	Electric Retail Revenues	$0	$0	$61,797	$0	$0		$0	$61,797	$61,797
2	Sales for Resale	0	0	0	0	0		0	0	0
3	Other Operating Revenue	0	0	0	0	0		0	0	0
4	Total Operating Revenues	0	0	61,797	0	0		0	61,797	61,797
	Operating Expenses									
5	Fuel, Purchased Power & Transmission	0	0	0	0	0		0	0	0
6	Other Operations and Maintenance Expense	75,798	66,667	0	(105,487)	0		0	36,978	412,987
7	Depreciation and Amortization	0	0	0	0	313,599		0	313,599	313,599
8	Taxes Other than Income Taxes	0	0	0	0	128,927		0	128,927	128,927
9	Income Taxes	0	0	0	0	0	124,178	(172,925)	(48,747)	(48,747)
10	Total Operating Expenses	75,798	66,667	0	(105,487)	442,526	124,178	(172,925)	430,757	806,766
11	Operating Income	($75,798)	($66,667)	$61,797	$105,487	($442,526)	($124,178)	$172,925	($368,960)	($744,969)

Supporting Schedules
Schedules THF C-3 through THF C-13

*Adjusted operating income before income taxesof I$13,502,396 less synchronized interest of $6,436,481 times the effective tax rate of .38598.

The normalized income tax expense is $2,727,302 vs Company pro forma of $2,121,267. Staff incremental adjustment should be $606,035, a net change of $124,176.

**based on adjusted operating income afer changes in pro forma adjustments which produce operating income before income tax of $13,069,751 less synchronized interest of $6,441,851 times the effective tax rate of 38.598%. This results in a normalized income tax expense of $2,554,377 vs. corrected level of $2,727,302, a net change of ($172,925).

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-04204A-09-0206

SURREBUTTAL

TESTIMONY

OF

DAVID C. PARCELL

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JANUARY 15, 2010

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SCHEDULES

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-09-0206

My Surrebuttal Testimony responds to certain parts of the Rebuttal Testimonies of UNS Electric, Inc.'s ("UNS Electric" or "Company") witnesses Pritz and Grant. I first respond to Ms. Pritz's Rebuttal Testimony on the issue of Cost of Common Equity. I demonstrate that her criticisms on my Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM") and Comparable Earnings methodologies and conclusions are without merit. I also explain why her "recalculations" of my DCF and CAPM analyses are not proper, but rather represent her attempts to apply her improper inputs into my analyses.

I next respond to Mr. Grant's Rebuttal Testimony on the issues of: 1) Ability of UNS Electric to earn its Cost of Capital; and 2) Rate of Return on Fair Value Rate Base. Regarding the first issue, my response is that regulation only provides the Company with the opportunity to earn a fair rate of return; it does not provide a guarantee. On the second issue, I disagree with Mr. Grant's interpretation of the Commission's recent decisions concerning the proper methodologies to determine the Fair Value Rate of Return. I further demonstrate that my proposed Fair Value Rate of Return proposal is consistent with past Commission decisions.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is David C. Parcell. I am President and Senior Economist of Technical Associates, Inc. My business address is Suite 601, 1051 East Cary Street, Richmond, Virginia 23219.

Q. Are you the same David C. Parcell who filed direct testimony on behalf of the Utilities Division Staff ("Staff") earlier in this proceeding?

A. Yes, I am.

Q. What is the purpose of your current testimony?

A. My current testimony is Surrebuttal Testimony in response to the Rebuttal Testimonies of UNS Electric Inc. ("UNS Electric" or "Company") witnesses Martha B. Pritz and Kentton C. Grant. I also updated my cost of capital analyses in this Surrebuttal Testimony.

Q. What aspects of Ms. Pritz's and Mr. Grant's Rebuttal Testimonies do you respond to in this Surrebuttal Testimony?

A. My Surrebuttal Testimony responds to the following general areas of Ms. Pritz's and Mr. Grant's Rebuttal Testimonies:

Cost of Common Equity (Ms. Pritz);
Ability of UNS Electric to Earn its Cost of Capital (Mr. Grant); and
Fair Value Rate of Return ("FVROR") (Mr. Grant).

COST OF COMMON EQUITY

Q. Ms. Pritz claims, on pages 1 and 2, that your cost of equity cost recommendation "is low due to the use of inappropriate inputs in several of the methods upon which he (you) relies." What is your response to this assertion?

A. I believe that my cost of equity recommendation is appropriate for UNS Electric at this time. This cost of equity recommendation is based upon the results of my Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM"), and Comparable Earnings ("CE") analyses and has been performed in a similar fashion to my recent testimonies before this Commission. I note that my 10.0 percent recommendation matches the cost of equity that the Commission found appropriate for UNS Electric in its most recent proceeding (i.e., Docket No. E-04204A-06-0783). There has been no demonstration that the cost of capital has increased since the 2007 proceeding of UNS Electric.

<u>DCF Issues</u>

Q. On pages 2-3, Ms. Pritz criticizes your DCF analyses and she characterizes some of your growth estimates as "weak sets of data as indications of dividend growth." What is your response to this assertion?

A. Ms. Pritz first takes issue with my use of historic data as one of several sources of growth projections. She next takes issue with my use of retention growth (both historic and prospective) as a growth indicator. What is implicit in her criticism is that her preferred short-term growth rates (i.e., exclusive use of analysts' forecasts of earnings per share growth) is all that is appropriate. I have previously noted in my direct testimony (pages 42-45) why it is improper to exclusively rely on earnings per share ("EPS") forecasts and also that such an exclusive reliance is not reflective of investor expectations.

Ms. Pritz attempts to justify her exclusive reliance on analysts' forecasts of EPS growth on her belief that "analysts providing forward-looking growth estimates will have already considered historical growth in determining the outlook for a company." This viewpoint is not a sufficient reason to assume that investors ignore historic growth and focus exclusively on analysts' forecasts. It should be apparent, based upon the experience of the past two years, that analysts have not been accurate in projecting EPS and, further, any investors who were unfortunate enough to have exclusively relied on such forecasts would have been sorely disappointed with their investment performance. In any event, recent performance of analysts' estimates would give investors even more reason to consider other growth indicators in making their investment decisions.

I further note that the preponderance of financial information provided to investors, both by individual companies and investment services such as Value Line, is historic data. It is neither realistic nor accurate to maintain that all of this information is ignored by investors, but this is what Ms. Pritz is maintaining.

Q. Ms. Pritz provides indications, on pages 2 and 3, reflecting her position of what your DCF results would be if you had not considered historic growth and retention growth in your analyses. Are these results meaningful?

A. No, they are not. These results simply reflect her attempt to substitute her proposal (i.e., exclusive use of analysts' estimates of EPS growth) into my DCF analyses. This is not proper and not an accurate portrayal of my DCF analyses.

Q. On page 5, Ms. Pritz claims that her use of historical gross domestic product ("GDP") growth is proper. What is your response to this?

A. I note, first of all, that Ms. Pritz maintains that short-term growth (in a DCF context) should only reflect prospective data, whereas long-term growth should only use historic data. This position is internally inconsistent. As I noted in my Direct Testimony (pages 45-47) prospective GDP growth is about 4.5 percent, well below that 6.5 percent level she uses.

In addition, Ms. Pritz's rebuttal testimony on page 5 implies that her 6.5 percent long-term growth rate reflects GDP projections. However, this is largely not the case, as she averages GDP estimates with other and higher growth rates, such as EPS projections and the "outlook for the electric utility industry."

__CAPM Issues__

Q. Ms. Pritz further maintains, on pages 7-9, that your use of both geometric and arithmetic means in your CAPM analysis is not proper. What is your response to this?

A. It is apparent that investors have access to both types of returns, and correspondingly use both types of returns, when they make investment decisions. In fact, it is noteworthy that mutual fund investors regularly receive reports on their own funds, as well as prospective funds they are considering investing in, that show only geometric returns. In fact, the Securities and Exchange Commission requires that returns be reported this way. Based on this, I find it difficult to accept Ms. Pritz's position that only arithmetic returns are considered by investors and, thus, only arithmetic returns are appropriate in a CAPM context. I note that I provided additional comments on this point in my Direct Testimony.

Q. Has this Commission recently made a finding as to whether it is appropriate to use geometric as well as arithmetic returns in this context?

A. Yes, it has. In Decision No. 70360 (UNS Electric Docket No. E-04204A-06-0783) the Commission specifically stated (page 43) that it agreed with the use of geometric returns in this manner: "We agree with the Staff that it is appropriate to consider the geometric returns in calculating a comparable company CAPM because to do otherwise would fail to give recognition to the fact that many investors have access to such information for purposes of making investment decisions." Therefore, the Company's position also conflicts with recent Commission orders on this issue.

Q. Ms. Pritz indicates her belief, on pages 7-8, that "income returns" (which she uses) is superior to "total returns" (which you use). What is your response to this?

A. I addressed this issue in my Direct Testimony on page 48.

Q. On pages 9-10, Ms. Pritz claims to have recalculated your CAPM cost of equity results. Is this a proper exercise?

A. No, it is not. Ms. Pritz's "recalculations" are simply her attempt to interject her CAPM components into my analyses. Such recalculations are incorrect and improper.

<u>Comparable Earnings Issues</u>

Q. Ms. Pritz also criticizes your comparable earnings analyses on page 6. What is your response to this position?

A. I disagree with Ms. Pritz. The book value of UNS Electric's capital, including common equity, is used to determine the Company's cost of capital. It is only natural that the returns on book value of equity (i.e., comparable earnings analyses) is an appropriate mechanism for estimating the cost of equity.

Q. Ms. Pritz also implies, on page 6, that market-to-book ratios do not indicate investor acceptance of earned returns. Is she correct?

A. No, she is not. Stock prices – one component of the market-to-book ratio – reflect all relevant information. For public utilities, the return on equity is a major component of the rate-setting process and clearly is reflected in stock prices, and thus market-to-book ratios. I also note that I consider expected returns on equity in my comparable earnings analysis.

ABILITY OF UNS ELECTRC TO EARN ITS COST OF CAPITAL

Q. Mr. Grant devotes several pages of his Rebuttal Testimony to his assertion that UNS Electric will not likely earn the cost of capital authorized in this proceeding. Is this a proper criticism of your Direct Testimony?

A. I do not believe it is proper rebuttal to my testimony. Mr. Grant seems to be taking the position that the cost of capital authorized by a commission should be regarded as a "guarantee" but this is not the case. Utility investors have no more "right" to a guaranteed return than do its ratepayers to a "right" to employment, maintenance of their housing values, and an increasing valve of their retirement accounts and other investments.

RATE OF RETURN ON FAIR VALUE RATE BASE

Q. Mr. Grant maintains, on page 10, that your FVROR recommendation to apply a zero percent return to the Fair Value Increment amounts to a "backing in" method of assigning a FVROR. Do you agree with his assessment?

A. No, I do not. My proposal specifically recognizes the value of the Fair Value Rate Base ("FVRB") increment and applies the actual cost of this capital (which is zero) to it. As such, I believe this proposal specifically recognizes and utilizes the FVRB in establishing rates.

Q. Mr. Grant also claims, on pages 10-11, that since the Commission did not adopt your FVROR proposal in the Chaparral City remand proceeding (Docket No. W-02113A-04-0616) that your proposal has been "rejected." What is your response to this?

A. It is my reading of the Chaparral City Remand Order[1] by the Commission that a similar procedure to what I recommended was adopted. I also note that the Commission stated in its Chaparral City Remand Order "we also believe that Staff's method is an appropriate way to adjust the Weighted Average Cost of Capital associated with the Original Cost Rate Base ("OCRB") for use with the FVRB, as it is based on sound economic and financial theory." (Decision No. 70441 at p. 37) In the UNS Gas and UNS Electric cases, the Commission did adopt my recommendation. Finally I note that the FVROR proposal of Chaparral City was the same as that proposed by UNS Gas and UNS Electric in their 2007 rate proceedings (Docket Nos. G-04204A-06-0463 and E-04204A-06-0783), namely that the original cost rate of return ("OCROR") be applied to the level of FVRB. In all three of these cases, the Commission did not adopt the Chaparral City/UNS Gas & Electric position.

Q. On pages 12-13, Mr. Grant maintains there is a mathematical error in your FVROR calculation and states that the correction of this "increases Staff's proposed revenue requirement by $633,000." What is your response to these assertions?

A. Mr. Grant is correct, on page 12, that my FVROR (as shown on page 57) should have stated 6.14 percent rather than 5.99 percent. However, this correction does not impact Staff's proposed revenue requirement.

[1] See, *In The Matter of the Application of Chaparral City Water Company, an Arizona Corporation, for a Determination of the Current Fair Value of its Utility Plant and Property and for Increases in its Rates and Charges for Utility Service Based Thereon.* Docket No. W-02113A-04-0616. Opinion and Order, Decision No. 70441 (July 28, 2008).

Q. Why is it the case that this correction does not impact Staff's proposed revenue requirement?

A. Mr. Grant's claim (i.e., that the difference between a 5.99 percent FVROR and a 6.14 percent FVROR) results in a $633,000 impact on Staff's proposed revenue requirement is based upon an assumption on his part that Utilities Division Staff witness Fish used the 5.99 percent number in developing the revenue requirement. This is not the case.

Dr. Fish did not use the 5.99 percent per se when developing his proposed revenue requirement. Rather, he developed his value for the fair value return by multiplying my proposed 1.50 percent return on the FVRB increment, or the difference between the fair value rate base and original cost rate base (see Dr. Fish's direct testimony, Schedule THF A-1). As a result, the mathematic error on my page 57 was not carried through by Dr. Fish to the Staff's revenue requirement, as stated by Mr. Grant.

Q. Aside from this correction of your "mathematical error" on page 57 of your Direct Testimony, do you have any additional comments on the FVROR calculation you are proposing in this proceeding?

A. Yes, I do. As I was in the process of reviewing my FVROR calculation, as shown on pages 54 and 57 of my Direct Testimony, I discovered that I had not properly developed the capital structure ratios to be used in the FVROR consistent with Staff's calculations in most other cases. I have subsequently corrected this, which is shown on Schedule 15 of my Surrebuttal Testimony. As a result, my recommendation is that the Commission adopt a FVROR of 6.01 percent.

Q. Please describe Schedule 15.

A. The top portion of Schedule 15 shows how the 6.14 percent (as corrected) FVROR was developed in my Direct Testimony. As this indicates, I developed the capital structure ratios by combining the dollars as long-term debt, common equity and FVRB Increment and calculating the respective percentages of each of the three items.

The problem I discovered with this process is that I was combining dollars of capital items (for long-term debt and common equity) with dollars of rate base (for FVRB Increment). Since the rate base and capital for UNS Electric (as well as most utilities) do not precisely match, the FVROR which I recommended in my Direct Testimony (i.e., 6.14 percent) was slightly different than the ultimate FVROR in Staff witness Dr. Fish's return on FVRB (i.e., 6.01 percent).

However, the proper way to develop the capital structure ratios for the FVROR calculation is to equate the capital structure percentages (for long-term debt and common equity) to the dollar values of original cost rate base. I did this on the bottom portion of Schedule 15. Here I applied the percentages of long-term debt and common equity (as shown in the development of the total cost of capital in Schedule 1 of my Direct Testimony) to the dollar value of OCRB to develop dollars of long-term debt and common equity that equate to OCRB. This is then combined with the dollar value of the FVRB Increment to develop a capital structure that equates to the value of FVRB. I then applied the cost rates of long-term debt (7.05 percent), common equity (10.00 percent) and FVRB Increment (1.50 percent) to the percentages to develop a FVROR that properly matches the value of FVRB. This produces a FVROR of 6.01 percent, which should have been my recommendation.

Q. Does this correction impact Staff's revenue requirement?

A. No, it does not. As I indicated previously, Dr. Fish did not directly use my proposed FVROR number in his calculation of the revenue requirement, but rather directly used the 1.50 percent FVRB Increment cost to arrive at a return on the FVRB. I have developed Schedule 15 to clarify the method by which the FVROR should be viewed in a cost of capital context.

UPDATES

Q. Have you updated your cost of capital analyses?

A. Yes, I have. My Direct Testimony utilized financial market data as of October of 2009. My DCF and CAPM analyses employed stock prices and interest rates for the three-month period July-September of 2009.

My updated analyses consider financial data through early January 2010 and incorporates stock prices and interest rates for the three-month period October-December 2009. I have also used the most recent editions of Value Line and analysts' forecasts of EPS in my updated analyses. My updated analyses also reflect a minor correction to my analyses that was identified in the Rebuttal Testimony of UNS Electric.

I have prepared a complete set of schedules to my exhibit. Any schedules that have been revised are identified as "updated."

Q. What is the impact of your cost of capital updates?

A. The table below identifies the impacts of my updates:

DCF Analyses

	Original Analyses		Updated Analyses	
	Proxy Group	Pritz Group	Proxy Group	Pritz Group
Mean	10.1%	9.5%	9.8%	9.2%
Median	9.6%	9.4%	10.1%	9.4%
Mean				
Low	8.6%	8.2%	8.0%	8.0%
High	12.3%	11.7%	13.0%	11.9%
Median				
Low	8.9%	7.4%	7.9%	6.9%
High	11.8%	11.6%	13.9%	11.3%

CAPM Analyses

	Original Analyses		Updated Analyses	
	Proxy Group	Pritz Group	Proxy Group	Pritz Group
Mean	8.3%	7.6%	8.2%	7.9%
Median	8.3%	8.0%	8.2%	7.9%

Based upon these updates, I conclude that the cost of capital for UNS Electric remains at the 10.0 percent level I derived in my Direct Testimony.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes, it does.

Exhibit___(DCP-1)
Schedule 1

UNS ELECTRIC INC
TOTAL COST OF CAPITAL

Item	Percent		Cost			Weighted Cost	
Long-Term Debt	54.24%		7.05%			3.82%	
Common Equity	45.76%	9.50%	-	10.50%	4.35%		4.80%
Total	100.00%				8.17%		8.63%
						8.40%	**With 10.0% ROE**

ECONOMIC INDICATORS

Year	Real GDP Growth*	Industrial Production Growth	Un-employment Rate	Consumer Price Index	Producer Price Index
			1975 - 1982 Cycle		
1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
1976	5.4%	10.8%	7.7%	4.8%	3.7%
1977	5.5%	5.9%	7.0%	6.8%	6.9%
1978	5.0%	5.7%	6.0%	9.0%	9.2%
1979	2.8%	4.4%	5.8%	13.3%	12.8%
1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
1981	1.8%	1.9%	7.5%	8.9%	7.1%
1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
			1983 - 1991 Cycle		
1983	4.0%	3.7%	9.5%	3.8%	0.6%
1984	6.8%	9.3%	7.5%	3.9%	1.7%
1985	3.7%	1.7%	7.2%	3.8%	1.8%
1986	3.1%	0.9%	7.0%	1.1%	-2.3%
1987	2.9%	4.9%	6.2%	4.4%	2.2%
1988	3.8%	4.5%	5.5%	4.4%	4.0%
1989	3.5%	1.8%	5.3%	4.6%	4.9%
1990	1.8%	-0.2%	5.6%	6.1%	5.7%
1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
			1992 - 2001 Cycle		
1992	3.0%	3.1%	7.5%	2.9%	1.6%
1993	2.7%	3.3%	6.9%	2.7%	0.2%
1994	4.0%	5.4%	6.1%	2.7%	1.7%
1995	2.5%	4.8%	5.6%	2.5%	2.3%
1996	3.7%	4.3%	5.4%	3.3%	2.8%
1997	4.5%	7.2%	4.9%	1.7%	-1.2%
1998	4.2%	6.1%	4.5%	1.6%	0.0%
1999	4.8%	4.3%	4.2%	2.7%	2.9%
2000	4.1%	4.2%	4.0%	3.4%	3.6%
2001	1.1%	-3.4%	4.7%	1.6%	-1.6%
			Current Cycle		
2002	1.8%	-0.1%	5.8%	2.4%	1.2%
2003	2.5%	1.3%	6.0%	1.9%	4.0%
2004	3.6%	2.5%	5.5%	3.3%	4.2%
2005	3.1%	3.3%	5.1%	3.4%	5.4%
2006	2.7%	2.3%	4.6%	2.5%	1.1%
2007	2.1%	1.5%	4.6%	4.1%	6.2%
2008	0.4%	-2.2%	5.8%	0.1%	-0.9%

*GDP=Gross Domestic Product

Source: Council of Economic Advisors, Economic Indicators, various issues.

ECONOMIC INDICATORS

Year	Real GDP Growth*	Industrial Production Growth	Un-employment Rate	Consumer Price Index	Producer Price Index
2002					
1st Qtr.	2.7%	-3.8%	5.6%	2.8%	4.4%
2nd Qtr.	2.2%	-1.2%	5.9%	0.9%	-2.0%
3rd Qtr.	2.4%	0.8%	5.8%	2.4%	1.2%
4th Qtr.	0.2%	1.4%	5.9%	1.6%	0.4%
2003					
1st Qtr.	1.2%	1.1%	5.8%	4.8%	5.6%
2nd Qtr.	3.5%	-0.9%	6.2%	0.0%	-0.5%
3rd Qtr.	7.5%	-0.9%	6.1%	3.2%	3.2%
4th Qtr.	2.7%	1.5%	5.9%	-0.3%	2.8%
2004					
1st Qtr.	3.0%	2.8%	5.6%	5.2%	5.2%
2nd Qtr.	3.5%	4.9%	5.6%	4.4%	4.4%
3rd Qtr.	3.6%	4.6%	5.4%	0.8%	0.8%
4th Qtr.	2.5%	4.3%	5.4%	3.6%	7.2%
2005					
1st Qtr.	4.1%	3.8%	5.3%	4.4%	5.6%
2nd Qtr.	1.7%	3.0%	5.1%	1.6%	-0.4%
3rd Qtr.	3.1%	2.7%	5.0%	8.8%	14.0%
4th Qtr.	2.1%	2.9%	4.9%	-2.0%	4.0%
2006					
1st Qtr.	5.4%	3.4%	4.7%	4.8%	-0.2%
2nd Qtr.	1.4%	4.5%	4.6%	4.8%	5.6%
3rd Qtr.	0.1%	5.2%	4.7%	0.4%	-4.4%
4th Qtr.	3.0%	3.5%	4.5%	0.0%	3.6%
2007					
1st Qtr.	1.2%	2.5%	4.5%	4.8%	6.4%
2nd Qtr.	3.2%	1.6%	4.5%	5.2%	6.8%
3rd Qtr.	3.6%	1.8%	4.6%	1.2%	1.2%
4th Qtr.	2.1%	1.7%	4.8%	5.6%	12.8%
2008					
1st Qtr.	-0.7%	1.8%	4.9%	2.8%	9.6%
2nd Qtr.	1.5%	-0.4%	5.4%	7.6%	14.0%
3rd Qtr.	-2.7%	-3.2%	6.1%	2.8%	-0.4%
4th Qtr.	-5.4%	-6.7%	6.9%	-13.2%	-28.4%
2009					
1st Qtr.	-6.4%	-11.6%	8.1%	2.4%	-1.2%
2nd Qtr.	-0.7%	-12.9%	9.3%	3.2%	8.8%
3rd Qtr.	2.8%	-9.5%	9.6%	2.4%	1.6%

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

Year	Prime Rate	US Treas T Bills 3 Month	US Treas T Bonds 10 Year	Utility Bonds Aaa	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
			1975 - 1982 Cycle				
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
			1983 - 1991 Cycle				
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
			1992 - 2001 Cycle				
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.45%	5.02%	7.47%	7.59%	7.78%	8.02%
			Current Cycle				
2002	4.67%	1.62%	4.61%	[1]	7.19%	7.37%	8.02%
2003	4.12%	1.02%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
2006	7.96%	4.73%	4.80%		5.84%	6.07%	6.32%
2007	8.05%	4.41%	4.63%		5.94%	6.07%	6.33%
2008	5.09%	1.48%	3.66%		6.18%	6.53%	7.25%

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

INTEREST RATES

Year	Prime Rate	US Treas T Bills 3 Month	US Treas T Bonds 10 Year	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
2003						
Jan	4.25%	1.17%	4.05%	6.87%	7.06%	7.47%
Feb	4.25%	1.16%	3.90%	6.66%	6.93%	7.17%
Mar	4.25%	1.13%	3.81%	6.56%	6.79%	7.05%
Apr	4.25%	1.14%	3.96%	6.47%	6.64%	6.94%
May	4.25%	1.08%	3.57%	6.20%	6.36%	6.47%
June	4.00%	0.95%	3.33%	6.12%	6.21%	6.30%
July	4.00%	0.90%	3.98%	6.37%	6.57%	6.67%
Aug	4.00%	0.96%	4.45%	6.48%	6.78%	7.08%
Sept	4.00%	0.95%	4.27%	6.30%	6.56%	6.87%
Oct	4.00%	0.93%	4.29%	6.28%	6.43%	6.79%
Nov	4.00%	0.94%	4.30%	6.26%	6.37%	6.69%
Dec	4.00%	0.90%	4.27%	6.18%	6.27%	6.61%
2004						
Jan	4.00%	0.89%	4.15%	6.06%	6.15%	6.47%
Feb	4.00%	0.92%	4.08%	6.10%	6.15%	6.28%
Mar	4.00%	0.94%	3.83%	5.93%	5.97%	6.12%
Apr	4.00%	0.94%	4.35%	6.33%	6.35%	6.46%
May	4.00%	1.04%	4.72%	6.66%	6.62%	6.75%
June	4.00%	1.27%	4.73%	6.30%	6.46%	6.84%
July	4.25%	1.35%	4.50%	6.09%	6.27%	6.67%
Aug	4.50%	1.48%	4.28%	5.95%	6.14%	6.45%
Sept	4.75%	1.65%	4.13%	5.79%	5.98%	6.27%
Oct	4.75%	1.75%	4.10%	5.74%	5.94%	6.17%
Nov	5.00%	2.06%	4.19%	5.79%	5.97%	6.16%
Dec	5.25%	2.20%	4.23%	5.78%	5.92%	6.10%
2005						
Jan	5.25%	2.32%	4.22%	5.68%	5.78%	5.95%
Feb	5.50%	2.53%	4.17%	5.55%	5.61%	5.76%
Mar	5.75%	2.75%	4.50%	5.76%	5.83%	6.01%
Apr	5.75%	2.79%	4.34%	5.56%	5.64%	5.95%
May	6.00%	2.86%	4.14%	5.39%	5.53%	5.88%
June	6.25%	2.99%	4.00%	5.05%	5.40%	5.70%
July	6.25%	3.22%	4.18%	5.18%	5.51%	5.81%
Aug	6.50%	3.45%	4.26%	5.23%	5.50%	5.80%
Sept	6.75%	3.47%	4.20%	5.27%	5.52%	5.83%
Oct	6.75%	3.70%	4.46%	5.50%	5.79%	6.08%
Nov	7.00%	3.90%	4.54%	5.59%	5.88%	6.19%
Dec	7.25%	3.89%	4.47%	5.55%	5.80%	6.14%
2006						
Jan	7.50%	4.20%	4.42%	5.50%	5.75%	6.06%
Feb	7.50%	4.41%	4.57%	5.55%	5.82%	6.11%
Mar	7.75%	4.51%	4.72%	5.71%	5.98%	6.26%
Apr	7.75%	4.59%	4.99%	6.02%	6.29%	6.54%
May	8.00%	4.72%	5.11%	6.16%	6.42%	6.59%
June	8.25%	4.79%	5.11%	6.16%	6.40%	6.61%
July	8.25%	4.96%	5.09%	6.13%	6.37%	6.61%
Aug	8.25%	4.98%	4.88%	5.97%	6.20%	6.43%
Sept	8.25%	4.82%	4.72%	5.81%	6.00%	6.26%
Oct	8.25%	4.89%	4.73%	5.80%	5.98%	6.24%
Nov	8.25%	4.95%	4.60%	5.61%	5.80%	6.04%
Dec	8.25%	4.85%	4.56%	5.62%	5.81%	6.06%
2007						
Jan	8.25%	4.96%	4.76%	5.78%	5.96%	6.16%
Feb	8.25%	5.02%	4.72%	5.73%	5.90%	6.10%
Mar	8.25%	4.97%	4.56%	5.66%	5.85%	6.10%
Apr	8.25%	4.88%	4.69%	5.83%	5.97%	6.24%
May	8.25%	4.77%	4.75%	5.86%	5.99%	6.23%
June	8.25%	4.63%	5.10%	6.18%	6.30%	6.54%
July	8.25%	4.84%	5.00%	6.11%	6.25%	6.49%
Aug	8.25%	4.34%	4.67%	6.11%	6.24%	6.51%
Sept	7.75%	4.01%	4.52%	6.10%	6.18%	6.45%
Oct	7.50%	3.97%	4.53%	6.04%	6.11%	6.36%
Nov	7.50%	3.49%	4.15%	5.87%	5.97%	6.27%
Dec	7.25%	3.08%	4.10%	6.03%	6.16%	6.51%
2008						
Jan	6.00%	2.86%	3.74%	5.87%	6.02%	6.35%
Feb	6.00%	2.21%	3.74%	6.04%	6.21%	6.60%
Mar	5.25%	1.38%	3.51%	5.99%	6.21%	6.68%
Apr	5.00%	1.32%	3.68%	5.98%	6.29%	6.82%
May	5.00%	1.71%	3.88%	6.07%	6.27%	6.79%
June	5.00%	1.90%	4.10%	6.19%	6.38%	6.93%
July	5.00%	1.72%	4.01%	6.13%	6.40%	6.97%
Aug	5.00%	1.79%	3.89%	6.09%	6.37%	6.98%
Sept	5.00%	1.46%	3.69%	6.13%	6.49%	7.15%
Oct	4.00%	0.84%	3.81%	6.95%	7.56%	8.58%
Nov	4.00%	0.30%	3.53%	6.83%	7.60%	8.98%
Dec	3.25%	0.04%	2.42%	5.93%	6.54%	8.13%
2009						
Jan	3.25%	0.12%	2.52%	6.01%	6.39%	7.90%
Feb	3.25%	0.31%	2.87%	6.11%	6.30%	7.74%
Mar	3.25%	0.25%	2.82%	6.14%	6.42%	8.00%
Apr	3.25%	0.17%	2.93%	6.20%	6.48%	8.03%
May	3.25%	0.15%	3.29%	6.23%	6.49%	7.76%
June	3.25%	0.17%	3.72%	6.13%	6.20%	7.30%
July	3.25%	0.19%	3.56%	5.63%	5.97%	6.87%
Aug	3.25%	0.18%	3.58%	5.33%	5.71%	6.36%
Sept	3.25%	13.00%	3.40%	5.15%	5.53%	6.12%
Oct	3.25%	0.08%	3.39%	5.23%	5.55%	6.14%
Nov	3.25%	0.05%	3.40%	5.33%	5.64%	6.18%

Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of *Economic* Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

Year	S&P Composite [1]	NASDAQ Composite [1]	DJIA	S&P D/P	S&P E/P
		1975 - 1982 Cycle			
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
		1983 - 1991 Cycle			
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988	[1]	[1]	2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
		1992 - 2001 Cycle			
1992	415.74	599.26	3,284.29	2.99%	4.22%
1993	451.21	715.16	3,522.06	2.78%	4.46%
1994	460.42	751.65	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22	3,783.67	10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
		Current Cycle			
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005	1,207.23	2,099.32	10,547.67	1.83%	5.36%
2006	1,310.46	2,263.41	11,408.67	1.87%	5.78%
2007	1,477.19	2,578.47	13,169.98	1.86%	5.29%
2008	1,220.04	2,161.65	11,252.62	2.37%	3.55%

[1] Note: this source did not publish the S&P Composite prior to 1988 and the NASDAQ Composite prior to 1991.

Source: Council of Economic Advisors, Economic Indicators, various issues.

STOCK PRICE INDICATORS

YEAR	S&P Composite	NASDAQ *Composite*	DJIA	S&P D/P	S&P E/P
2002					
1st Qtr.	1,131.56	1,879.85	10,105.27	1.39%	2.15%
2nd Qtr.	1,068.45	1,641.53	9,912.70	1.49%	2.70%
3rd Qtr.	894.65	1,308.17	8,487.59	1.76%	3.68%
4th Qtr.	887.91	1,346.07	8,400.17	1.79%	3.14%
2003					
1st Qtr.	860.03	1,350.44	8,122.83	1.89%	3.57%
2nd Qtr.	938.00	1,521.92	8,684.52	1.75%	3.55%
3rd Qtr.	1,000.50	1,765.96	9,310.57	1.74%	3.87%
4th Qtr.	1,056.42	1,934.71	9,856.44	1.69%	4.38%
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
3rd Qtr.	1,225.91	2,144.61	10,532.24	1.83%	5.42%
4th Qtr.	1,262.07	2,246.09	10,827.79	1.86%	5.60%
2006					
1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	5.86%
3rd Qtr.	1,288.40	2,141.97	11,274.49	1.91%	5.88%
4th Qtr.	1,389.48	2,390.26	12,175.30	1.81%	5.75%
2007					
1st Qtr.	1,425.30	2,444.85	12,470.97	1.84%	5.85%
2nd Qtr.	1,496.43	2,552.37	13,214.26	1.82%	5.65%
3rd Qtr.	1,490.81	2,609.68	13,488.43	1.86%	5.15%
4th Qtr.	1,494.09	2,701.59	13,502.95	1.91%	4.51%
2008					
1st Qtr.	1,350.19	2,332.91	12,383.86	2.11%	4.57%
2nd Qtr.	1,371.65	2,426.26	12,508.59	2.10%	4.01%
3rd Qtr.	1,251.94	2,290.87	11,322.40	2.29%	3.94%
4th Qtr.	909.80	1,599.64	8,795.61	2.98%	1.65%
2009					
1st Qtr.	809.31	1,485.14	7,774.06	3.00%	0.86%
2nd Qtr.	892.23	1,731.41	8,327.83	2.45%	0.82%
3rd Qtr.	996.70	996.70	9,229.93	2.16%	1.20%

[1] Note: this source did not publish the S&P Composite prior to 1988 and the NASDAQ Composite prior to 1991.

Source: Council of Economic Advisors, Economic Indicators, various issues.

Exhibit___(DCP-1)
Schedule 3

UNISOURCE ENERGY CORPORATION
SEGMENT FINANCIAL INFORMATION
2006 - 2008
($millions)

Segment	Operating Revenues	Operating Income	Total Assets
		2006	
Tucson Electric Power Co	$989	$216	$2,623
	75.6%	90.0%	82.3%
UNS Gas	$162	$13	$253
	12.4%	5.4%	7.9%
UNS Electric	$160	$13	$195
	12.2%	5.4%	6.1%
All Other	$14		$1,038
	1.1%	0.0%	32.6%
Unisource Energy	$1,308	$240	$3,187
		2007	
Tucson Electric Power Co	$1,071	$189	$2,573
	77.6%	88.7%	80.8%
UNS Gas	$151	$12	$276
	10.9%	5.6%	8.7%
UNS Electric	$169	$12	$231
	12.2%	5.6%	7.3%
All Other	$12		$1,077
	0.9%	0.0%	33.8%
Unisource Energy	$1,381	$213	$3,186
		2008	
Tucson Electric Power Co	$1,079	$107	$2,842
	77.2%	73.8%	81.0%
UNS Gas	$174	$20	$294
	12.4%	13.8%	8.4%
UNS Electric	$195	$12	$285
	13.9%	8.3%	8.1%
All Other	$23		$1,061
	1.6%	0.0%	30.2%
Unisource Energy	$1,398	$145	$3,510

UNS Gas, TEP and UNS Electric figures do not total to Unisource Energy cosolidated figures due to other activities of Unisource Energy.

Source: Unisource Energy Corporation 2008 Form 10-K.

UNS ELECTRIC
CAPITAL STRUCTURE RATIOS
2003 - 2009
($millions)

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
2004	$40,900	$60,000	$600
	40.3%	59.1%	0.6%
	40.5%	59.5%	
2005	$49,900	$60,000	$500
	45.2%	54.3%	0.5%
	45.4%	54.6%	
2006	$64,900	$79,000	$400
	45.0%	54.7%	0.3%
	45.1%	54.9%	
2007	$79,800	$86,000	$400
	48.0%	51.7%	0.2%
	48.1%	51.9%	
2008	$83,800	$108,000	$200
	43.6%	56.3%	0.1%
	43.7%	56.3%	
June 30, 2009	$86,000	$100,000	$200
	46.2%	53.7%	0.1%
	46.2%	53.8%	

Source: Response to STF 7.2

UNISOURCE ENERGY CORP
CAPITAL STRUCTURE RATIOS
2003 - 2008
($millions)

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
2004	$581	$1,258	$0
	31.6%	68.4%	0.0%
	31.6%	68.4%	
2005	$617	$1,212	$5
	33.6%	66.1%	0.3%
	33.7%	66.3%	
2006	$654	$1,171	$50
	34.9%	62.5%	2.7%
	35.8%	64.2%	
2007	$690	$994	$10
	40.7%	58.7%	0.6%
	41.0%	59.0%	
2008	$679	$1,314	$10
	33.9%	65.6%	0.5%
	34.1%	65.9%	

Source: Unisource Energy Corporation 2008 Form 10-K.

UNISOURCE ENERGY AND UTILITY SUBSIDIARIES
CAPITAL STRUCTURE RATIOS
2008
($millions)

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
Unisource	$679.3	$1,313.6	$10.0
Energy	33.9%	65.6%	0.5%
consolidated	34.1%	65.9%	
UNS Gas	$96.7	$100.0	$0
	49.2%	50.8%	0.0%
	49.2%	50.8%	
UNS Electric	$83.8	$108.0	$200
	21.4%	27.6%	51.0%
	43.7%	56.3%	
TEP	$583.6	$903.6	$10.0
	39.0%	60.4%	0.7%
	39.2%	60.8%	

Source for Unisource Energy Consolidated and TEP is 2008 10-K
Source for UNS Gas and UNS Electric is Response to STF 7.2.

Exhibit___(DCP-1)
Schedule 5

PROXY GROUPS
COMMON EQUITY RATIOS

COMPANY	2004	2005	2006	2007	2008	Average	2012-2014
Parcell Proxy Group							
Avista Corp.	41.9%	40.6%	46.3%	59.0%	51.9%	47.9%	50.0%
Hawaiian Electric Industries, Inc	51.0%	53.3%	48.6%	51.0%	52.7%	51.3%	55.0%
Northeast Utilities	34.0%	35.1%	39.7%	39.2%	38.1%	37.2%	44.0%
Pinnacle West Capital Corp.	53.3%	56.8%	51.6%	53.0%	53.2%	53.6%	50.0%
Pepco Holdings, Inc.	39.6%	42.3%	45.1%	45.9%	43.8%	43.3%	48.5%
TECO Energy, Inc.	24.9%	30.0%	35.0%	39.0%	38.5%	33.5%	41.5%
Westar Energy, Inc.	45.5%	47.2%	49.3%	48.9%	49.7%	48.1%	52.5%
Average	41.5%	43.6%	45.1%	48.0%	46.8%	45.0%	48.8%
Pritz Comparable Company Group							
ALLETE, Inc.	61.8%	60.9%	64.9%	64.4%	58.4%	62.1%	51.5%
CH Energy Group, Inc.	59.1%	58.0%	58.8%	55.2%	54.6%	57.1%	48.5%
Empire District Electric Co.	48.7%	49.0%	50.3%	49.9%	46.4%	48.9%	49.0%
Hawaiian Electric Industries	51.0%	53.3%	48.6%	51.0%	52.7%	51.3%	55.0%
MGE Energy, Inc.	62.6%	60.7%	61.3%	64.8%	63.7%	62.6%	65.0%
Northeast Utilities	34.0%	35.1%	39.7%	39.2%	38.1%	37.2%	44.0%
NorthWestern Corp.							
NSTAR	40.2%	38.6%	39.7%	40.1%	42.8%	40.3%	54.0%
Portland General Electric	58.9%	57.7%	56.6%	50.1%	53.8%	55.4%	50.5%
UIL Holdings	52.8%	52.8%	53.0%	49.2%	46.4%	50.8%	48.0%
Average	52.1%	51.8%	52.5%	51.5%	50.8%	51.8%	51.7%

Source: Value Line.

Exhibit___(DCP-1)
Schedule 6

PROXY COMPANIES
BASIS FOR SELECTION

Company	Market Capitalization ($ millions)	Percent Reg Elec or Gas Revenues	Common Equity Ratio	Value Line Safety	S&P Bond Rating	Moody's Bond Rating
Unisource Energy	$975,000	84%	39%	3	NR	NR
Parcell Proxy Group						
Avista Corp.	$1,000,000	53%	54%	3	BBB+	Baa1
Hawaiian Electric Industries, Inc.	$1,600,000	98%	46%	3	BBB	Baa2
Northeast Utilities	$3,600,000	81%	41%	3	BBB+	A3
Pinnacle West Capital Corp.	$3,300,000	97%	45%	3	BBB-	Baa2
Pepco Holdings, Inc.	$3,100,000	50%	43%	3	A-	Baa1
TECO Energy, Inc.	$2,800,000	63%	39%	3	BBB	Baa1
Westar Energy, Inc.	$2,300,000	71%	44%	2	BBB-	Baa2
Pritz Comparable Company Group						
ALLETE, Inc.	$1,100,000	90%	58%	2	A-	A2
CH Energy Group, Inc.	$750,000	49%	49%	1	A	A2
Empire District Electric Co.	$625,000	86%	43%	3	BBB+	Baa1
Hawaiian Electric Industries	$1,600,000	98%	46%	3	BBB	Baa2
MGE Energy, Inc.	$850,000	59%	64%	1	AA-	Aa2
Northeast Utilities	$4,100,000	81%	41%	3	BBB+	A3
NorthWestern Corp.						
NSTAR	$3,400,000	80%	43%	1	AA-	A1
Portland General Electric	$1,400,000	98%	49%	2	A	Baa1
UIL Holdings	$775,000	100%	45%	2	NR	Baa2

Sources: AUS Utility Reports, Value Line.

COMPARISON COMPANIES
DIVIDEND YIELD

COMPANY	Qtr DPS	October - December, 2009 DPS	HIGH	LOW	AVERAGE	YIELD
Parcell Proxy Group						
Avista Corp.	$0.21	$0.84	$22.44	$18.48	$20.46	4.1%
Hawaiian Electric Industries, Inc.	$0.31	$1.24	$21.55	$17.64	$19.60	6.3%
Northeast Utilities	$0.24	$0.95	$26.48	$22.20	$24.34	3.9%
Pinnacle West Capital Corp.	$0.53	$2.10	$37.96	$31.08	$34.52	6.1%
Pepco Holdings, Inc.	$0.27	$1.08	$17.51	$14.24	$15.88	6.8%
TECO Energy, Inc.	$0.20	$0.80	$16.71	$13.45	$15.08	5.3%
Westar Energy, Inc.	$0.30	$1.20	$22.30	$18.91	$20.61	5.8%
Average						**5.5%**
Pritz Comparable Company Group						
ALLETE, Inc.	$0.44	$1.76	$35.29	$32.23	$33.76	5.2%
CH Energy Group, Inc.	$0.54	$2.16	$45.57	$39.54	$42.56	5.1%
Empire District Electric Co.	$0.32	$1.28	$19.36	$17.78	$18.57	6.9%
Hawaiian Electric Industries	$0.31	$1.24	$21.55	$17.64	$19.60	6.3%
MGE Energy, Inc.	$0.37	$1.47	$36.97	$33.41	$35.19	4.2%
Northeast Utilities	$0.24	$0.95	$26.48	$22.20	$24.34	3.9%
NorthWestern Corp.	$0.34	$1.34	$26.85	$23.61	$25.23	5.3%
NSTAR	$0.38	$1.50	$37.75	$30.76	$34.26	4.4%
Portland General Electric	$0.26	$1.02	$21.39	$18.25	$19.82	5.1%
UIL Holdings	$0.43	$1.73	$29.00	$25.27	$27.14	6.4%
Average						**5.3%**

Source: Yahoo! Finance.

COMPARISON COMPANIES
RETENTION GROWTH RATES

COMPANY	2004	2005	2006	2007	2008	Average	2009	2010	2012-'14	Average
Parcell Proxy Group										
Avista Corp.	1.4%	2.4%	4.9%	0.8%	3.7%	2.6%	4.0%	3.5%	3.0%	3.5%
Hawaiian Electric Industries, Inc.	1.1%	1.5%	0.7%	0.8%	0.5%	0.9%	0.0%	1.5%	3.0%	1.5%
Northeast Utilities	1.6%	1.5%	0.3%	4.3%	5.3%	2.6%	4.5%	4.5%	4.0%	4.3%
Pinnacle West Capital Corp.	2.3%	1.0%	3.4%	2.5%	0.3%	1.9%	1.0%	2.0%	3.0%	2.0%
Pepco Holdings, Inc.	2.5%	2.4%	1.5%	2.3%	4.2%	2.6%	0.0%	1.0%	2.5%	1.2%
TECO Energy, Inc.	0.0%	3.3%	5.0%	5.1%	0.0%	2.7%	2.0%	3.5%	4.5%	3.3%
Westar Energy, Inc.	3.2%	4.3%	5.5%	4.3%	1.2%	3.7%	1.0%	2.0%	2.5%	1.8%
Average						**2.4%**				**2.5%**
Pritz Comparable Company Group										
ALLETE, Inc.	4.7%	5.2%	5.0%	5.8%	3.9%	4.9%	0.0%	1.0%	2.0%	1.0%
CH Energy Group, Inc.	1.7%	2.0%	1.2%	1.6%	0.4%	1.4%	0.5%	1.5%	2.5%	1.5%
Empire District Electric Co.	0.0%	0.0%	0.8%	0.0%	0.0%	0.2%	0.0%	0.5%	2.5%	1.0%
Hawaiian Electric Industries	1.1%	1.5%	0.7%	0.8%	0.5%	0.9%	0.0%	1.5%	3.0%	1.5%
MGE Energy, Inc.	2.3%	1.2%	3.7%	4.3%	4.4%	3.2%	3.0%	4.0%	5.5%	4.2%
Northeast Utilities	1.6%	1.5%	0.3%	4.3%	5.3%	2.6%	4.5%	4.5%	4.0%	4.3%
NorthWestern Corp.	5.8%	4.2%	0.8%	0.7%	2.3%	2.8%				
NSTAR	4.8%	4.6%	4.9%	4.9%	4.9%	4.8%	5.0%	5.0%	6.0%	5.3%
Portland General Electric	7.2%	5.3%	3.5%	6.6%	2.0%	4.9%	2.5%	3.0%	3.5%	3.0%
UIL Holdings	0.0%	0.0%	0.0%	3.1%	1.0%	0.8%	1.0%	1.5%	2.5%	1.7%
Average						**2.6%**				**2.6%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
PER SHARE GROWTH RATES

COMPANY	5-Year Historic Growth Rates EPS	DPS	BVPS	Average	Est'd '06-'08 to '12-'14 Growth Rates EPS	DPS	BVPS	Average
Parcell Proxy Group								
Avista Corp.	4.0%	5.0%	3.0%	4.0%	6.5%	11.5%	3.5%	7.2%
Hawaiian Electric Industries, Inc.	-6.0%	0.0%	1.0%	-1.7%	7.0%	0.0%	2.0%	3.0%
Northeast Utilities	3.0%	8.5%	2.0%	4.5%	8.0%	7.0%	4.5%	6.5%
Pinnacle West Capital Corp.	-1.0%	5.0%	3.0%	2.3%	3.0%	1.0%	1.0%	1.7%
Pepco Holdings, Inc.	-2.0%	17.5%	1.5%	5.7%	NMF	NMF	1.0%	1.0%
TECO Energy, Inc.	-5.0%	-9.0%	-6.5%	-6.8%	4.5%	2.5%	4.5%	3.8%
Westar Energy, Inc.	21.5%	-0.5%	1.0%	7.3%	4.0%	4.5%	6.0%	4.8%
Average				**2.2%**				**4.0%**
Pritz Comparable Company Group								
ALLETE, Inc.					-1.0%	3.0%	3.0%	1.7%
CH Energy Group, Inc.	-1.5%	0.0%	1.5%	0.0%	3.5%	0.0%	2.0%	1.8%
Empire District Electric Co.	3.5%	0.0%	1.5%	1.7%	6.0%	1.0%	1.5%	2.8%
Hawaiian Electric Industries	-6.0%	0.0%	1.0%	-1.7%	7.0%	0.0%	2.0%	3.0%
MGE Energy, Inc.	6.0%	1.0%	8.0%	5.0%	6.0%	0.5%	7.0%	4.5%
Northeast Utilities	3.0%	8.5%	2.0%	4.5%	8.0%	7.0%	4.5%	6.5%
NorthWestern Corp.	--	--	--					
NSTAR	4.0%	6.0%	5.0%	5.0%	8.0%	5.5%	5.5%	6.3%
Portland General Electric	--	--	--		3.5%	5.5%	2.5%	3.8%
UIL Holdings	--	--	-2.0%	-2.0%	3.0%	0.0%	2.5%	1.8%
Average				**1.8%**				**3.6%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
DCF COST RATES

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Parcell Proxy Group								
Avista Corp.	4.2%	2.6%	3.5%	4.0%	7.2%	5.0%	4.5%	8.7%
Hawaiian Electric Industries, Inc.	6.5%	0.9%	1.5%		3.0%	10.5%	4.0%	10.4%
Northeast Utilities	4.0%	2.6%	4.3%	4.5%	6.5%	9.3%	5.5%	9.5%
Pinnacle West Capital Corp.	6.2%	1.9%	2.0%	2.3%	1.7%	8.0%	3.2%	9.4%
Pepco Holdings, Inc.	6.9%	2.6%	1.2%	5.7%	1.0%	5.5%	3.2%	10.1%
TECO Energy, Inc.	5.4%	2.7%	3.3%		3.8%	9.8%	4.9%	10.4%
Westar Energy, Inc.	5.9%	3.7%	1.8%	7.3%	4.8%	3.7%	4.3%	10.2%
Mean	5.6%	2.4%	2.5%	4.8%	4.0%	7.4%	4.2%	**9.8%**
Median	5.9%	2.6%	2.0%	4.5%	3.8%	8.0%	4.3%	**10.1%**
Composite - Mean		**8.0%**	8.1%	10.4%	9.6%	**13.0%**	9.8%	
Composite - Median		8.5%	**7.9%**	10.4%	9.8%	**13.9%**	10.2%	
Pritz Comparable Company Group								
ALLETE, Inc.	5.3%	4.9%	1.0%		1.7%	4.0%	2.9%	8.2%
CH Energy Group, Inc.	5.1%	1.4%	1.5%		1.8%	N/A	1.6%	6.7%
Empire District Electric Co.	7.0%	0.2%	1.0%	1.7%	2.8%	6.0%	2.3%	9.3%
Hawaiian Electric Industries	6.5%	0.9%	1.5%		3.0%	10.5%	4.0%	10.4%
MGE Energy, Inc.	4.3%	3.2%	4.2%	5.0%	4.5%	5.0%	4.4%	8.6%
Northeast Utilities	4.0%	2.6%	4.3%	4.5%	6.5%	9.3%	5.5%	9.5%
NorthWestern Corp.	5.4%	2.8%				7.0%	4.9%	10.3%
NSTAR	4.5%	4.8%	5.3%	5.0%	6.3%	5.7%	5.4%	9.9%
Portland General Electric	5.3%	4.9%	3.0%		3.8%	6.8%	4.6%	9.9%
UIL Holdings	6.4%	0.8%	1.7%		1.8%	4.5%	2.2%	8.6%
Mean	5.4%	2.6%	2.6%	4.0%	3.6%	6.5%	3.8%	**9.2%**
Median	5.3%	2.7%	1.7%	4.8%	3.0%	6.0%	4.2%	**9.4%**
Composite - Mean		**8.0%**	8.0%	9.4%	9.0%	**11.9%**	9.2%	
Composite - Median		8.0%	**6.9%**	10.0%	8.3%	**11.3%**	9.5%	

Sources: Prior pages of this schedule.

Exhibit___(DCP-1)
Schedule 8
Updated

STANDARD & POOR'S 500 COMPOSITE
20-YEAR U.S. TREASURY BOND YIELDS
RISK PREMIUMS

Year	EPS	BVPS	ROE	20-YEAR T-BOND YIELD	RISK PREMIUM
1977		$79.07			
1978	$12.33	$85.35	15.00%	7.90%	7.10%
1979	$14.86	$94.27	16.55%	8.86%	7.69%
1980	$14.82	$102.48	15.06%	9.97%	5.09%
1981	$15.36	$109.43	14.50%	11.55%	2.95%
1982	$12.64	$112.46	11.39%	13.50%	-2.11%
1983	$14.03	$116.93	12.23%	10.38%	1.85%
1984	$16.64	$122.47	13.90%	11.74%	2.16%
1985	$14.61	$125.20	11.80%	11.25%	0.55%
1986	$14.48	$126.82	11.49%	8.98%	2.51%
1987	$17.50	$134.04	13.42%	7.92%	5.50%
1988	$23.75	$141.32	17.25%	8.97%	8.28%
1989	$22.87	$147.26	15.85%	8.81%	7.04%
1990	$21.73	$153.01	14.47%	8.19%	6.28%
1991	$16.29	$158.85	10.45%	8.22%	2.23%
1992	$19.09	$149.74	12.37%	7.29%	5.08%
1993	$21.89	$180.88	13.24%	7.17%	6.07%
1994	$30.60	$193.06	16.37%	6.59%	9.78%
1995	$33.96	$215.51	16.62%	7.60%	9.02%
1996	$38.73	$237.08	17.11%	6.18%	10.93%
1997	$39.72	$249.52	16.33%	6.64%	9.69%
1998	$37.71	$266.40	14.62%	5.83%	8.79%
1999	$48.17	$290.68	17.29%	5.57%	11.72%
2000	$50.00	$325.80	16.22%	6.50%	9.72%
2001	$24.69	$338.37	7.43%	5.53%	1.90%
2002	$27.59	$321.72	8.36%	5.59%	2.77%
2003	$48.73	$367.17	14.15%	4.80%	9.35%
2004	$58.55	$414.75	14.98%	5.02%	9.96%
2005	$69.93	$453.06	16.12%	4.69%	11.43%
2006	$81.51	$504.39	17.03%	4.68%	12.35%
2007	$66.18	$529.59	12.50%	4.86%	7.64%
2008	$14.88	$451.37	3.30%	4.45%	-1.15%
Average					**6.20%**

Source: Standard & Poor's Analysts' Handbook, Ibbotson Associates Handbook.

Exhibit___(DCP-1)
Schedule 9
Updated

COMPARISON COMPANIES
CAPM COST RATES

COMPANY	RISK-FREE RATE	BETA	RISK PREMIUM	CAPM RATES
Parcell Proxy Group				
Avista Corp.	4.27%	0.70	5.23%	7.9%
Hawaiian Electric Industries, Inc.	4.27%	0.70	5.23%	7.9%
Northeast Utilities	4.27%	0.70	5.23%	7.9%
Pinnacle West Capital Corp.	4.27%	0.75	5.23%	8.2%
Pepco Holdings, Inc.	4.27%	0.80	5.23%	8.5%
TECO Energy, Inc.	4.27%	0.85	5.23%	8.7%
Westar Energy, Inc.	4.27%	0.75	5.23%	8.2%
Mean				**8.2%**
Median				**8.2%**
Pritz Comparable Company Group				
ALLETE, Inc.	4.27%	0.70	5.23%	7.9%
CH Energy Group, Inc.	4.27%	0.65	5.23%	7.7%
Empire District Electric Co.	4.27%	0.75	5.23%	8.2%
Hawaiian Electric Industries	4.27%	0.70	5.23%	7.9%
MGE Energy, Inc.	4.27%	0.65	5.23%	7.7%
Northeast Utilities	4.27%	0.70	5.23%	7.9%
NorthWestern Corp.	4.27%	0.70	5.23%	7.9%
NSTAR	4.27%	0.65	5.23%	7.7%
Portland General Electric	4.27%	0.70	5.23%	7.9%
UIL Holdings	4.27%	0.70	5.23%	7.9%
Mean				**7.9%**
Median				**7.9%**

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

20-year Treasury Bonds

Month	Rate
Oct, 2009	4.16%
Nov, 2009	4.24%
Dec, 2009	4.40%

COMPARISON COMPANIES
RATES OF RETURN ON AVERAGE COMMON EQUITY

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	1992-2001 Average	2002-2009 Average	2010	2012-14
Parcell Proxy Group																						
Avista Corp.	11.7%	12.2%	10.5%	11.2%	10.6%	15.0%	10.2%	1.1%	13.4%	7.9%	4.5%	6.7%	4.6%	5.8%	8.8%	4.1%	7.6%	8.1%	10.4%	5.3%	8.0%	8.5%
Hawaiian Electric Industries, Ir	*10.9%*	*10.5%*	*11.1%*	*11.0%*	*10.5%*	*10.9%*	*11.5%*	*11.1%*	*9.8%*	*12.4%*	*11.9%*	*11.1%*	*9.3%*	*9.7%*	*9.3%*	*7.7%*	*7.0%*	*7.5%*	*11.0%*	*9.2%*	*9.5%*	*10.5%*
Northeast Utilities	12.6%	9.4%	12.6%	11.9%	0.1%	-6.2%	-2.3%	-7.3%	-1.3%	8.6%	6.4%	7.1%	5.1%	5.4%	4.5%	8.6%	9.8%	9.6%	3.8%	7.1%	9.0%	9.5%
Pinnacle West Capital Corp.	10.7%	10.9%	10.2%	10.6%	11.2%	11.9%	11.5%	12.3%	12.4%	12.8%	8.6%	8.3%	8.2%	6.7%	9.2%	8.5%	6.1%	6.9%	11.5%	7.8%	8.0%	9.0%
Pepco Holdings, Inc.	10.6%	12.0%	10.8%	10.5%	11.7%	10.5%	11.3%	11.7%	8.9%	11.9%	9.8%	7.6%	8.3%	8.1%	7.1%	7.9%	9.9%	6.3%	11.0%	8.1%	7.0%	7.5%
TECO Energy, Inc.	16.1%	15.1%	14.5%	16.6%	16.5%	14.8%	13.5%	13.8%	17.4%	17.2%	13.5%	-0.7%	9.2%	14.2%	14.7%	14.3%	8.1%	11.0%	15.6%	10.5%	11.5%	12.0%
Westar Energy, Inc.	11.0%	12.4%	10.7%	11.1%	10.4%	-1.6%	7.1%	5.2%	3.2%	-2.2%	5.0%	10.6%	7.7%	9.6%	11.1%	10.0%	6.7%	8.2%	6.7%	8.6%	7.5%	7.5%
Average	11.9%	11.8%	11.5%	11.8%	10.1%	7.9%	9.0%	6.9%	9.1%	9.8%	8.5%	7.2%	7.5%	8.5%	9.2%	8.7%	7.9%	8.2%	10.0%	8.2%	8.8%	9.2%
Median	11.0%	12.0%	10.8%	11.1%	10.6%	10.9%	11.3%	11.1%	9.8%	11.9%	8.6%	7.6%	8.2%	8.1%	9.2%	8.5%	7.6%	8.1%	11.1%	8.2%	8.0%	9.0%
Pritz Comparable Company Group																						
ALLETE, Inc.														12.0%	13.2%	13.4%	11.4%	7.6%		11.5%	8.0%	9.0%
CH Energy Group, Inc.	*11.0%*	*11.1%*	*10.7%*	*10.7%*	*11.3%*	*10.9%*	*10.4%*	*10.2%*	*10.5%*	*10.4%*	*7.0%*	*9.1%*	*8.7%*	*8.9%*	*7.9%*	*8.2%*	*6.7%*	*6.6%*	*9.5%*	*7.9%*	*7.5%*	*8.5%*
Empire District Electric Co.	10.3%	9.4%	10.6%	9.4%	9.4%	9.9%	11.6%	8.4%	10.0%	4.3%	8.4%	8.7%	5.7%	6.2%	9.2%	6.9%	7.4%	9.6%	8.6%	7.8%	8.5%	10.5%
Hawaiian Electric Industries	10.9%	10.5%	11.1%	11.0%	10.5%	10.9%	11.5%	11.1%	9.8%	12.4%	11.9%	11.1%	9.3%	9.7%	9.3%	7.7%	7.0%	7.5%	11.0%	9.2%	9.5%	10.5%
MGE Energy, Inc.	13.1%	13.3%	13.1%	12.5%	7.1%	12.5%	12.2%	13.0%	14.2%	13.1%	13.2%	12.5%	11.4%	9.4%	11.9%	12.1%	11.8%	11.2%	12.1%	11.7%	10.5%	12.0%
Northeast Utilities	12.6%	9.4%	12.6%	11.9%	0.1%	-6.2%	-2.3%	-7.3%	-1.3%	8.6%	6.4%	7.1%	5.1%	5.4%	4.5%	8.6%	9.8%	9.6%	3.8%	7.1%	9.0%	9.5%
NorthWestern Corp.																						
NSTAR	11.4%	11.9%	12.2%	10.2%	12.6%	12.6%	12.5%	11.4%	12.3%	13.4%	14.0%	13.9%	13.4%	13.1%	13.2%	13.5%	13.6%	13.7%	12.7%	13.6%	13.5%	15.0%
Portland General Electric	12.9%	12.0%	11.3%	13.4%	13.9%										5.9%	11.5%	6.5%	6.4%	12.7%	7.6%	8.0%	8.5%
UIL Holdings	9.2%	10.4%	10.5%	11.8%	10.1%	10.4%	9.5%	11.6%	12.8%	12.1%	8.9%	6.1%	7.1%	5.7%	9.1%	10.1%	10.1%	9.9%	9.7%	8.4%	10.0%	10.5%
Average	11.4%	11.0%	11.5%	11.4%	9.4%	8.7%	9.4%	8.4%	9.8%	10.6%	10.0%	9.8%	8.7%	8.8%	9.4%	10.2%	9.4%	9.1%	10.0%	9.4%	9.4%	10.4%
Median	11.2%	10.8%	11.2%	11.4%	10.3%	10.9%	11.5%	11.1%	10.5%	12.1%	8.9%	9.1%	8.7%	9.2%	9.2%	10.1%	9.8%	9.6%	11.1%	9.3%	9.0%	10.5%

Source: *Calculations made from data contained in Value Line Investment Survey.*

COMPARISON COMPANIES
MARKET TO BOOK RATIOS

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	1992-2001 Average	2002-2009 Average
Parcell Proxy Group																				
Avista Corp.	151%	163%	133%	125%	145%	162%	163%	152%	317%	114%	85%	94%	111%	115%	135%	127%	110%	88%	163%	108%
Hawaiian Electric Industries,	171%	154%	141%	149%	147%	147%	154%	132%	127%	145%	153%	151%	179%	181%	192%	166%	166%	114%	147%	163%
Northeast Utilities	154%	149%	127%	124%	95%	64%	91%	113%	136%	129%	99%	95%	106%	108%	131%	163%	128%	112%	118%	118%
Pinnacle West Capital Corp.	116%	125%	99%	116%	133%	152%	180%	143%	145%	154%	116%	114%	130%	130%	129%	127%	100%	86%	136%	117%
Pepco Holdings, Inc.	160%	162%	135%	138%	161%	151%	161%	166%	139%	124%	110%	103%	109%	122%	129%	141%	115%	75%	150%	113%
TECO Energy, Inc.	243%	268%	224%	238%	241%	234%	247%	210%	223%	222%	135%	111%	174%	243%	202%	188%	171%	116%	235%	167%
Westar Energy, Inc.	144%	152%	130%	129%	126%	131%	128%	89%	74%	78%	67%	109%	132%	142%	139%	140%	107%	87%	118%	115%
Average	163%	168%	141%	146%	150%	149%	180%	144%	166%	138%	109%	111%	134%	149%	151%	150%	128%	97%	**152%**	**129%**
Median	154%	154%	133%	129%	145%	151%	161%	143%	139%	129%	110%	109%	130%	130%	135%	141%	115%	88%	**144%**	**120%**
Pritz Comparable Company Group																				
ALLETE, Inc.													322%	212%	219%	195%	156%	113%	203%	203%
CH Energy Group, Inc.	123%	133%	107%	112%	114%	135%	155%	133%	125%	141%	152%	147%	149%	146%	154%	145%	132%	133%	135%	145%
Empire District Electric Co.	184%	178%	143%	142%	143%	138%	168%	177%	183%	162%	132%	133%	144%	148%	149%	150%	122%	99%	150%	135%
Hawaiian Electric Industries	171%	154%	141%	149%	147%	147%	154%	132%	127%	145%	153%	151%	179%	181%	192%	166%	166%	114%	147%	163%
MGE Energy, Inc.	189%	196%	189%	183%	203%	189%	197%	177%	172%	197%	214%	223%	207%	207%	191%	178%	160%	151%	190%	191%
Northeast Utilities	154%	149%	127%	124%	95%	64%	91%	113%	136%	129%	99%	95%	106%	108%	131%	163%	128%	112%	118%	118%
NorthWestern Corp.																				
NSTAR	138%	154%	130%	130%	125%	146%	181%	166%	161%	161%	170%	175%	189%	202%	214%	222%	201%	187%	170%	195%
Portland General Electric	115%	125%	112%	140%	199%										153%	140%	101%	80%	138%	119%
UIL Holdings	123%	157%	127%	123%	114%	111%	151%	144%	141%	139%	126%	113%	133%	135%	174%	189%	168%	126%	139%	146%
Average	150%	156%	135%	138%	142%	133%	157%	149%	149%	153%	150%	148%	179%	167%	175%	172%	148%	124%	**154%**	**157%**
Median	146%	154%	129%	135%	134%	138%	155%	144%	141%	145%	152%	147%	164%	165%	174%	166%	156%	114%	**142%**	**155%**

Source: Calculations made from data contained in Value Line Investment Survey.

STANDARD & POOR'S 500 COMPOSITE RETURNS AND MARKET-TO-BOOK RATIOS 1992 - 2008

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
1992	12.2%	271%
1993	13.2%	272%
1994	16.4%	246%
1995	16.6%	264%
1996	17.1%	299%
1997	16.3%	354%
1998	14.6%	421%
1999	17.3%	481%
2000	16.2%	453%
2001	7.5%	353%
2002	8.4%	296%
2003	14.2%	278%
2004	15.0%	291%
2005	16,1%	278%
2006	17.0%	277%
2007	12.8%	284%
2008	3.3%	224%
Averages:		
1992-2001	14.7%	341%
2002-2008	12.4%	275%

Source: Standard & Poor's Analyst's Handbook, 2008 edition, page 1.

Exhibit___(DCP-1)
Schedule 12
Updated

RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.05	B++	B
Parcell Proxy Group	2.9	0.75	B+	B
Pritz Comparable Company Group	2.1	0.69	A-	A-

Sources: Value Line Investment Survey, Standard & Poor's Stock Guide.

Definitions:

Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk.

Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.

Financial strengths range from C to A++, with the latter representing the highest level.

Common stock rankings range from D to A+, with the later representing the highest level.

Exhibit___(DCP-1)
Schedule 13
Updated

UNS ELECTRIC INC
RATING AGENCY RATIOS

Item	Percent	Cost	Weighted Cost	Pre-Tax Cost	
Long-Term Debt	54.24%	7.05%	3.82%	3.82%	
Common Equity	45.76%	10.00%	4.58%	7.63%	
Total	100.00%		8.40%	11.45%	1/

1/ Post-tax weighted cost divided by .60 (composite tax factor)

Pre-Tax coverage = **2.99**
11.45% /3.82%

Standard & Poor's Utility Benchmark Ratios: Business Profile of "4"	A	BBB
Pre-tax coverage	3.3x - 4.0x	2.2x - 3.0x
Total debt to total capital	45%-52%	52%-62%

LONG-TERM PROJECTIONS OF GROSS DOMESTIC PRODUCT GROWTH

Social Security Administration

Year	Real GDP	GDP Index	Nominal GDP	Year	Real GDP	GDP Index	Nominal GDP
2008	2.3%	2.0%	4.3%	2049	2.2%	2.4%	4.6%
2009	2.8%	2.1%	4.9%	2050	2.1%	2.4%	4.5%
2010	2.7%	2.4%	5.1%	2051	2.1%	2.4%	4.5%
2011	2.5%	2.4%	4.9%	2052	2.1%	2.4%	4.5%
2012	2.5%	2.4%	4.9%	2053	2.1%	2.4%	4.5%
2013	2.5%	2.4%	4.9%	2054	2.1%	2.4%	4.5%
2014	2.4%	2.4%	4.8%	2055	2.1%	2.4%	4.5%
2015	2.3%	2.4%	4.7%	2056	2.1%	2.4%	4.5%
2016	2.3%	2.4%	4.7%	2057	2.1%	2.4%	4.5%
2017	2.3%	2.4%	4.7%	2058	2.1%	2.4%	4.5%
2018	2.3%	2.4%	4.7%	2059	2.1%	2.4%	4.5%
2019	2.3%	2.4%	4.7%	2060	2.1%	2.4%	4.5%
2020	2.2%	2.4%	4.6%	2061	2.1%	2.4%	4.5%
2021	2.2%	2.4%	4.6%	2062	2.1%	2.4%	4.5%
2022	2.2%	2.4%	4.6%	2063	2.1%	2.4%	4.5%
2023	2.2%	2.4%	4.6%	2064	2.1%	2.4%	4.5%
2024	2.2%	2.4%	4.6%	2065	2.1%	2.4%	4.5%
2025	2.1%	2.4%	4.5%	2066	2.1%	2.4%	4.5%
2026	2.1%	2.4%	4.5%	2067	2.1%	2.4%	4.5%
2027	2.1%	2.4%	4.5%	2068	2.1%	2.4%	4.5%
2028	2.1%	2.4%	4.5%	2069	2.1%	2.4%	4.5%
2029	2.1%	2.4%	4.5%	2070	2.1%	2.4%	4.5%
2030	2.1%	2.4%	4.5%	2071	2.1%	2.4%	4.5%
2031	2.1%	2.4%	4.5%	2072	2.1%	2.4%	4.5%
2032	2.1%	2.4%	4.5%	2073	2.1%	2.4%	4.5%
2033	2.1%	2.4%	4.5%	2074	2.1%	2.4%	4.5%
2034	2.1%	2.4%	4.5%	2075	2.1%	2.4%	4.5%
2035	2.2%	2.4%	4.6%	2076	2.1%	2.4%	4.5%
2036	2.2%	2.4%	4.6%	2077	2.1%	2.4%	4.5%
2037	2.2%	2.4%	4.6%	2078	2.1%	2.4%	4.5%
2038	2.2%	2.4%	4.6%	2079	2.1%	2.4%	4.5%
2039	2.2%	2.4%	4.6%	2080	2.1%	2.4%	4.5%
2040	2.2%	2.4%	4.6%	2081	2.1%	2.4%	4.5%
2041	2.2%	2.4%	4.6%	2082	2.1%	2.4%	4.5%
2042	2.2%	2.4%	4.6%				
2043	2.2%	2.4%	4.6%				
2044	2.2%	2.4%	4.6%				
2045	2.2%	2.4%	4.6%				
2046	2.2%	2.4%	4.6%				
2047	2.2%	2.4%	4.6%	Average			**4.6%**
2048	2.2%	2.4%	4.6%				

Source: 2007 OASDI Trustees Report.

LONG-TERM PROJECTIONS OF GROSS DOMESTIC PRODUCT GROWTH

Energy Information Administration

Annual Growth (2005-2030):

Real GDP	2.4%
GDP Chain-type Price Index	2.0%
Nominal GDP Growth	**4.4%**

Source: Energy Information Administration, Annual Energy Outlook 2008 with Projections to 2030.

Exhibit___(DCP-1)
Schedule 15

RECALCULATION OF FAIR VALUE RATE OF RETURN

Calculation of FVROR as used on pages 54 and 57 of Parcell testimony

	Dollars		Percent	Cost	Wgt Cost	
Long-term Debt	$99,300,000	1/	36.45%	7.05%	2.57%	
Common Equity	$83,800,000	1/	30.76%	10.00%	3.08%	
FVRB Increment	$89,333,154	2/	32.79%	1.50%	0.49%	3/
						4/
	$272,433,154				6.14%	

1/ Dollars of long-term debt and common equity, as used in UNS Electric filing to develop Company's cost of capital.
2/ Differential between FVRB and OCRB, as developed by Staff witness Fish.
3/ This corrects for the mistake on page 57, where 0.34% was incorrectly shown.
4/ This corrects for the mistake on page 57, where 5.99% was incorrectly shown.

This analysis, as developed on page 54, combines the dollars of long-term debt and common equity, with the dollars of the FVRB Increment.

Recalculation of FVROR to reflect matching of OCRB with values of long-term debt and common equity.

FVRB	$257,949,478
OCRB	$168,616,324
FVRB Increment	$89,333,154

	Percent 5/				
Long-term Debt	54.24%	$91,457,494	35.46%	7.05%	2.50%
Common Equity	45.76%	$77,158,830	29.91%	10.00%	2.99%
FVRB Increment		$89,333,154	34.63%	1.50%	0.52%
Fair Value Rate Base		$257,949,478	100.00%		6.01%

5/ Percentages of long-term debt and common equity as shown on Schedule 1.

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. E-04204A-09-0206

SURREBUTTAL

TESTIMONY

OF

W. MICHAEL LEWIS, P.E.

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JANUARY 15, 2010

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
E-04204A-09-0206

The surrebuttal testimony of W. Michael Lewis of W. M. Lewis and Associates, Inc. ("WML&A") presents certain observations and responses to the rebuttal testimony of Mr. McKenna filed on behalf of UNS Electric ("UNSE"). Specifically, Mr. Lewis's rebuttal testimony addresses UNSE's water supply and treatment facilities at the Black Mountain Generating Station ("BMGS"), the thermal scanning of the BMGS substation, and the contents of an annual report to the Arizona Corporation Commission ("Commission") regarding UNSE's distribution network indices.

With regard to the water supply and treatment facilities at BMGS, Mr. McKenna's rebuttal testimony described a nearly complete raw water supply project. This is a project we were not aware of at the time of the filing of direct testimony that addresses our concerns regarding sufficient water supply at the BMGS. On another matter, Mr. Lewis' direct testimony recommended annual thermal scanning of the BMGS substation. In Mr. McKenna's rebuttal testimony, he does not commit to the annual scanning of the BMGS substation. We continue to recommend that UNSE employ thermal scanning at the BMGS substation on an annual basis, but that this should not be contingent on a Commission order. In our view, such an order from the Commission is unnecessary and would be micro-managing UNSE's operations and maintenance programs.

Lastly, Mr. McKenna's rebuttal testimony does not object to the filing by UNSE with the Commission of an annual report regarding distribution network indices, but does object to the identification of the worst performing circuits. We believe that these circuits should be identified in an annual report since the indice values represent average performance in a service area, which can be misleading. This can be the case since some customers may be experiencing more outages (in frequency and/or duration) associated with the more poorly performing circuits.

Q. Please state your name and business address.

A. My name is William Michael Lewis. My business address is 934 Valley Street, Wheelersburg, Ohio 45694.

Q. Have you previously pre-filed testimony in this proceeding?

A. Yes.

Q. What is the nature of your Surrebuttal Testimony?

A. My Surrebuttal Testimony is in response to various references to my Direct Testimony presented in the Rebuttal Testimony of Mr. McKenna filed on behalf of UNS Electric, Inc. ("UNSE").

Q. Please cite these references and your responses.

A. At page 6 of his rebuttal, Mr. McKenna responded to my recommendation that UNSE address limitations on water availability as required for operations at the Black Mountain Generating Station ("BMGS"). Mr. McKenna presented a diagram of the station water supply and treatment facilities and explained that a project to increase raw water supply is apparently close to completion. This project evidently will increase the water supply by some 125 gallons per minute ("gpm").

Q. Does that address your concerns as to water limitations?

A. It does. I was not aware of this project when I prepared my Direct Testimony. I would note that this project does add a redundant source for about 53 percent of the raw water requirements which does address my concerns as to raw water supply. There are other considerations as to the requirements for treated (demineralized) water production and storage, however, the added raw water supply does address the stated concerns in my Direct Testimony.

Q. Please continue.

A. Mr. McKenna responded to my recommendation that thermal scanning be employed at the BMGS substation on an annual basis. Mr. McKenna noted that UNSE selectively uses this scanning on an annual basis in some service areas, and will do so at the BMGS substation if ordered to do so by the Commission. I assume Mr. McKenna's statement indicates that UNSE will undertake annual scanning of the BMGS substation if ordered by the Commission.

Q. What is your response?

A. I do not understand the implied reluctance to employ thermal scanning at the BMGS substation. Thermal scanning is effective in locating, e.g., loose connections. UNSE apparently agrees as noted by Mr. McKenna's description of using scanning after maintenance at other substations. BMGS, as with peaking operations in general, subjects its associated station works to full thermal stress on a regular, if not daily, basis which can lead to poor connections and other bus problems. Given that UNSE evidently has the necessary equipment in-house or on-call and experience in the use of the results of thermal scans, it doesn't seem reasonable that such would not be employed at the BMGS substation or that it would require an order to do so.

Q. What was another of Mr. McKenna's references to your testimony?

A. At page 19, starting at line 20, Mr. McKenna stated that my testimony was "only partially accurate."

Q. How do you respond to that?

A. I can only state that my testimony as to UNSE's past practice of data collection was based upon my understanding of statements made during a meeting with the Tucson Electric Power personnel who were preparing the indices in response to our initial data requests regarding quality of service indices.

Q. Does Mr. McKenna's clarification affect your subsequent testimony?

A. No.

Q. Mr. McKenna does not agree with your recommendation that UNSE provides a listing of the worst performing circuits in an annual report of the distribution indices. How do you respond and why do you feel that such reporting is necessary?

A. The distribution indices represent an average performance in the affected service area or areas. If, in fact, some customers are experiencing much worse outages, either in frequency or duration, then otherwise acceptable values of indices are, or can be, misleading. A listing of the more poorly performing circuits can indicate to what extent that is the case, and what measures could be taken to mitigate the problems.

Q. How do you respond to Mr. McKenna's concerns as to the effect of such a submission?

A. I believe that Staff is aware of the problems inherent in addressing specific reliability problems as discussed by Mr. McKenna and will not have any unreasonable expectations as to the timing and nature of corrective actions. I do agree that this listing of specific circuits will result in an incentive to UNSE to address them in a timely manner.

Q. Are there other comments in Mr. McKenna's Rebuttal Testimony that you feel should be addressed?

A. Yes. Mr. McKenna stated at page 13 of his Rebuttal Testimony that my conclusion that the Call Center operates in an effective manner "further justifies" the costs for the Call Center as proposed by UNSE in Mr. Duke's Direct Testimony. I do not agree with that statement as the costs of the Call Center were not considered in my review of the operation and procedures of the Call Center. My only consideration was the Call Center's handling of the notification and restoration of service outages.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. E-04204A-09-0206

RATE DESIGN

SURREBUTTAL

TESTIMONY

OF

WILLIAM C. STEWART

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JANUARY 15, 2010

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SCHEDULES

Schedules Accompanying
The Surrebuttal Testimony of William C. Stewart

Schedule	Description
WCS H-1S	Summary of Revenues by Customer Classification
WCS H-2S	Comparison of Revenues by Rate Schedule
WCS H-3S	Comparison of Present and Proposed Rates
WCS H-4S	Present and Proposed Rates

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-09-0206

The purpose of my Surrebuttal Testimony is to respond to certain issues raised by Company witness Erdwurm in his Rebuttal Testimony. The issues I address include the Customer Assistance Residential Energy Support ("CARES") program for low-income customers, CARES Purchased Power and Fuel Adjustment Clause ("PPFAC"), and rate changes.

Staff recommends that possible changes in qualifications for CARES and other low income programs be discussed by interested parties. Staff also recommends that its recommendation for PPFAC treatment for CARES customers be adopted by the Commission.

Staff also provides revised proposed rate schedules. Although there are minor changes in the H Schedules as a result of the information provided in the Company's Rebuttal Testimony, the Company and Staff proposed percentage increases are not changed. The Company is proposing the following percentage increases to adjusted test year revenues:

Customer Class	Percentage change
Total	8.48%
Residential	9.21%
Residential CARES	-9.41%
Small General Service	9.21%
Large General Service	9.21%
Large Power Service	9.21%
Interruptible Power Service	9.21%
Lighting	9.21%

Staff proposes the following percentage increases to adjusted test year revenues:

Customer Class	Percentage Change
Total	4.76%
Residential	5.17%
Residential CARES	-5.23%
Small General Service	5.17%
Large General Service	5.17%
Large Power Service	5.17%
Interruptible Power Service	5.17%
Lighting	5.17%

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is William C. Stewart. I am employed by Ariadair Economics Group as a utility analyst. My business address is 1020 Fredericksburg Road, Excelsior Springs, Missouri 64024.

Q. What is the purpose of your Surrebuttal Testimony?

A. The purpose of my Surrebuttal Testimony is to respond to certain issues raised by Company witness Erdwurm in his Rebuttal Testimony. The issues I address include the Customer Assistance Residential Energy Support ("CARES") program for low-income customers, CARES Purchased Power and Fuel Adjustment Clause ("PPFAC"), and rate changes.

Q. Did you revised your Schedules as a result of your analysis and review?

A. Yes. In my Direct Testimony, I prepared Schedules WCS H-1 through WCS H-4 based on a gross revenue requirement increase of $7,517,565 as provided by Dr. Fish. Dr. Fish has modified the gross revenue requirement increase to $7,579,110 in his Surrebuttal Testimony. Therefore, I have recalculated these Schedules based on the modified gross revenue requirement and present them as Schedule WCS H-1S, WCS H-2S, WCS H-3S, and WCS H-4S attached.

CARES PROGRAM

Q. Does Mr. Erdwurm recommend increasing CARES eligibility from 150 percent to 200 percent of poverty level?

A. In his Direct Testimony at page 3, Mr. Erdwurm recommends "...to expand low-income assistance programs to households with incomes of up to 200 percent of poverty."

However, in his Rebuttal Testimony at page 12, Mr. Erdwurm states "expansion of the program (CARES) could be costly and UNS Electric, Inc. ("UNS Electric", "UNSE" or "Company") stands by its position that its support of expanded low income programs is contingent on program costs being fully recovered from other retail customers on a timely basis." Mr. Erdwurm seems to be backing away from his earlier recommendation.

Q. What is Staff's position with respect to expanding qualification for the CARES program?

A. Staff is not opposed to expanding qualification for the CARES program. However, Staff believes that before significant expansion of the program is proposed, the structure of any such expansion should be determined on the basis of consultation between the Company, Staff, Residential Utility Consumer Office, and any other interested parties.

CARES PPFAC

Q. Does Mr. Erdwurm support your recommendation with respect to CARES customers' PPFAC charges?

A. No. Staff recommends that the PPFAC rate for CARES customers be frozen at zero except if a reduction in fuel and purchased power costs results in a negative PPFAC rate. Mr. Erdwurm argues at page 12 of his Rebuttal Testimony that it is unfair for CARES customers to enjoy a reduction in the PPFAC if they do not incur increases in the PPFAC rate.

Q. Do you agree with Mr. Erdwurm's argument with respect to this issue?

A. No. The purpose of the CARES program is to provide an opportunity for those UNSE customers who are facing more difficult economic circumstances than their more fortunate neighbors to obtain electric service. Mr. Erdwurm's objection ignores this fact.

RATE CHANGES

Q. Is it clear from proposed rates that the Company is actually requesting an increase in rates?

A. The possibility exists for some confusion as to the actual impact of the Company's request for a rate increase. The H Schedules provided by the Company showing its current and proposed rates shows a rate decrease as a result of the Company's rate request as does Staff's H Schedules in the Direct Testimony and in this Surrebuttal Testimony.

Q. What is the cause of the apparent reduction in rates associated with the application for rate relief?

A. The cause of the apparent reduction is the treatment of the PPFAC. It is common for electric utilities to reset their PPFAC to zero when they request rate relief and that was done in this case.

Q. How did resetting the PPFAC to zero affect the Company's rate structure?

A. The Company's original PPFAC rate went into effect June 1, 2008 at +1.4746 cents/kWh. Some of the highest recorded oil and natural gas costs occurred around this time. Subsequently, energy prices declined significantly. UNS Electric submitted its Annual Update to its December 31, 2008 PPFAC Report on April 1, 2009. This report indicated that the PPFAC would be reset to -1.0564 cents/kWh on June 1, 2009, for a reduction of 2.5310 cents/kWh. As part of its rate case filing, the Company proposed resetting its PPFAC to zero. This, in turn, required that the average cents per kWh of base rates be reduced by -1.0564 cents/kWh. This reduction in base rates offset the resetting of PPFAC to zero but might give the appearance that the application for a rate increase results in lower rates.

Q. Would resetting the PPFAC rate to -1.0564 cents/kWh clear up the possible confusion?

A. No. Resetting the PPFAC rate to -1.0564 would require increasing the average kWh base rate by that amount so that the aggregate impact would be the same.

Q. Does that conclude your Surrebuttal Testimony?

A. Yes.

UNS Electric, Inc.
Summary of Revenues by Customer Classifications-Stewart Surrebuttal Testimony
Adjusted Present Rates And Proposed Rates
Test Year Ended December 31, 2008

Line No.	Class of Service	Test Year Present Net Revenue	Adjusted Present Net Revenue	Proposed Net Revenue	Staff Proposed Net Increase	Proposed Percent Increase to Test Year Revenues (a)	Proposed Percent Increase to Adjusted Test Year Revenues (a)	Line No.
1	Residential Service	$85,575,371	$74,148,720	$77,983,215	$3,834,494	4.48%	5.17%	1
2	Residential Cares	6,547,952	6,355,558	6,023,183	($332,375)	-5.08%	-5.23%	2
3	Small General Service	11,642,400	10,569,832	11,116,435	$546,604	4.69%	5.17%	3
4	Large General Service	55,358,044	48,286,092	50,783,138	$2,497,046	4.51%	5.17%	4
5	Large Power Service	19,626,605	16,938,518	17,814,468	$875,950	4.46%	5.17%	5
6	Interruptible Service	2,271,247	2,481,084	2,609,390	$128,306	5.65%	5.17%	6
7	Lighting DD	617,297	562,438	591,524	$29,086	4.71%	5.17%	7
8	Subtotal	181,638,915	159,342,242	166,921,353	7,579,110	4.17%	4.76%	8
9	Other Operating Revenue	$1,645,619	$1,645,619	1,645,619	$0	0.00%	0.00%	9
10	Total	$183,284,534	$160,987,861	$168,566,971	$7,579,110	4.14%	4.71%	10

Supporting Schedules	Recap Schedules	Recap Schedules
(a) H-2 (P2)	A-1	A-1

UNS Electric, Inc.
Comparisons of Revenues by Rate Schedules-Stewart Surrebuttal Testimony
Present And Proposed Rates
Test Year Ended December 31, 2008

				Actual				Adjusted			
Line No.	Class of Service	Rate Schedule Present	Proposed	kWh Sales	Average Number of Customers	Average kWh per Customer	Test Year End Sales Adjustments	kWh Sales	Average Number of Customers	Average Sales per Customer	Line No.
1	Residential Service	RES-01	RES-01	757,895,043	71,505	10,599	(17,627,814)	740,267,229	70,602	10,485	1
2	Residential Cares	CARES	CARES	63,995,155	6,869	9,317	5,725,945	69,721,100	7,522	9,269	2
3	Small General Service	SGS-10	SGS-10	92,855,781	7,711	12,042	570,617	93,426,398	7,778	12,012	3
4	Large General Service	LGS	LGS	498,893,145	2,069	241,167	(19,755,862)	479,137,283	2,000	239,569	4
5	Large General Service TOU	LGS-TOU	LGS-TOU	3,045,144	11	287,730	(45,296)	2,999,848	10	299,985	5
6	Large Power Service <69KV	LPS	LPS	60,317,878	9	6,520,852	3,946,904	64,264,781	11	5,842,253	6
7	Large Power Service >69KV	LPS	LPS	158,685,112	8	19,835,639	0	158,685,112	8	19,835,639	7
8	Interruptible Power Service	IPS	IPS	24,484,630	25	989,278	7,021,780	31,506,409	34	926,659	8
9	Lighting	LTG	LTG	3,145,228	1,781	1,766	0	3,145,228	1,781	1,766	9
10	Total Electric Retail Service			1,663,317,115	89,986	18,484	(20,163,726)	1,643,153,389	89,746	18,309	10

UNS Electric, Inc.
Comparisons of Revenues by Rate Schedules-Stewart Surrebuttal Testimony
Present And Proposed Rates
Test Year Ended December 31, 2008

Line No.	Class of Service	Company Adjusted Net Revenue	Proposed TY Delivery Charge Revenue	Proposed Increase Delivery $	Proposed Increase Delivery %	Proposed TY Base Power Supply Revenue	Proposed TY Total Revenue Requirement	Line No.
1	Residential Service	$74,148,720	$18,648,666	$3,901,405	20.92%	$55,380,872	$77,930,943	1
1	Residential Cares	$6,355,558	$1,066,561	-202,697	-19.00%	4,996,214	$5,860,079	1
2	Small General Service	$10,569,832	3,776,052	550,223	14.57%	6,787,334	11,113,609	2
3	Large General Service	$47,992,353	17,307,444	2,406,067	13.90%	30,820,985	50,534,495	3
4	Large General Service TOU	$293,739	101,622	14,106	13.88%	192,968	308,696	4
5	Large Power Service <69KV	$5,736,652	2,507,990	257,206	10.26%	3,283,095	6,048,291	5
6	Large Power Service >69KV	$11,201,866	3,229,525	512,728	15.88%	8,106,746	11,848,999	6
7	Interruptible Power Service	$2,481,084	827,912	114,933	13.88%	1,676,992	2,619,837	7
8	Lighting	$562,438	511,110	25,147	4.92%	58,344	594,602	8
9	Total Electric Service	$159,342,242	$47,976,882	$7,579,118	15.80%	$111,303,550	$166,859,551	9

(1) Adjustments include Customer Annualization, Weather Normalization, Cares Discount and PPFAC Adjustment)

	Present Rate	Proposed Rate	Increase $	Increase %
Residential Service				
Customer Charge	$7.50	$8.00	$0.50	6.67%
Energy Charge 1st 400 kWhs	$0.011255	$0.016204	$0.004949	43.97%
Energy Charge, all additional kWhs	$0.021269	$0.026218	$0.004949	23.27%
Base Power Supply Charge, all kWhs	$0.077993	$0.076207	-$0.001786	-2.29%
PPFAC	$0.014746	$0.000000	-$0.014746	-100.00%
Residential Service CARES				
Customer Charge	$7.50	$3.50	-$4.00	-53.33%
Energy Charge 1st 400 kWhs	$0.011255	$0.011255	$0.000000	0.00%
Energy Charge, all additional kWhs	$0.021269	$0.021269	$0.000000	0.00%
Base Power Supply Charge, all kWhs	$0.077993	$0.074438	-$0.003555	-4.56%
PPFAC	$0.014746	$0.000000	-$0.014746	-100.00%
Residential Time of Use Rates, all kWhs				
(These rates would include all Delivery charges above and replace The Base Power Supply charge)				
Summer on-peak	$0.092183	$0.160533	$0.068350	74.15%
Summer Shoulder	$0.081803	$0.076207	-$0.005596	-6.84%
Summer off-peak	$0.077183	$0.055553	-$0.021630	-28.02%
Winter on-peak	$0.080873	$0.160533	$0.079660	98.50%
Winter off-peak	$0.065873	$0.043289	-$0.022584	-34.28%
Small General Service				
Customer Charge	$12.00	$12.50	$0.50	4.17%
Energy Charge 1st 400 kWhs	$0.022449	$0.028058	$0.005609	24.99%
Energy Charge, all additional kWhs	$0.032463	$0.038072	$0.005609	17.28%
Base Power Supply Charge, all kWhs	$0.075738	$0.074004	-$0.001734	-2.29%
PPFAC	$0.014746	$0.000000	-$0.014746	-100.00%
Small General Service Time of Use Rates, all kWhs				
(These rates would include all Delivery charges above and replace The Base Power Supply charge)				
Summer on-peak	$0.090348	$0.138114	$0.047766	52.87%
Summer Shoulder	$0.079658	$0.074004	-$0.005654	-7.10%
Summer off-peak	$0.075348	$0.048114	-$0.027234	-36.14%
Winter on-peak	$0.079448	$0.138114	$0.058666	73.84%
Winter off-peak	$0.064448	$0.039894	-$0.024554	-38.10%

Large General Service

Customer Charge	$15.50	$16.00	$0.50	3.23%
Demand Charge, per kW	$10.71	$13.35	$2.64	24.68%
Energy Charge (kWhs)	$0.003254	$0.003815	$0.000561	17.25%
Base Power Supply Charge, all kWhs	$0.067062	$0.065786	-$0.001276	-1.90%
PPFAC	$0.014746	$0.000000	-$0.014746	-100.00%

Large General Service TOU

Customer Charge	$20.40	$20.90	$0.50	2.45%
Demand Charge, per kW	$10.71	$13.35	$2.64	24.68%
Energy Charge (kWhs)	$0.003254	$0.003815	$0.000561	17.25%
Base Power Supply Charge, all kWhs	$0.067062	$0.065526	-$0.001536	-2.29%
PPFAC	$0.014746	$0.000000	-$0.014746	-100.00%

Large General Service Time of Use Rates, all kWhs

(These rates would include all Delivery charges above and replace The Base Power Supply charge)

Summer on-peak	$0.082832	$0.122421	$0.039589	47.79%
Summer Shoulder	$0.071452	$0.065526	-$0.005926	-8.29%
Summer off-peak	$0.067832	$0.047421	-$0.020411	-30.09%
Winter on-peak	$0.071072	$0.122421	$0.051349	72.25%
Winter off-peak	$0.056072	$0.033703	-$0.022369	-39.89%

Large Power Service (<69KV)

Customer Charge	$365.00	$372.00	$7.00	1.92%
Demand Charge, per kW	$17.90	$21.22	$3.33	18.59%
Energy Charge (kWhs)	$0.000000	($0.000000)	$0.000000	0.00%
Base Power Supply Charge, all kWhs	$0.053260	$0.052040	-$0.001220	-2.29%
PPFAC	$0.014746	$0.000000	-$0.014746	-100.00%

Large Power Service (>69KV)

Customer Charge	$400.00	$407.00	$7.00	1.75%
Demand Charge, per kW	$11.61	$14.93	$3.32	0.00%
Energy Charge (kWhs)	$0.000000	($0.000000)	$0.000000	0.00%
Base Power Supply Charge, all kWhs	$0.053260	$0.052040	-$0.001220	-2.29%
PPFAC	$0.014746	$0.000000	-$0.014746	100.00%

Large Power Service Time of Use Rates, all kWhs

(These rates would include all Delivery charges above and replace The Base Power Supply charge)

Summer on-peak	$0.070170	$0.100000	$0.029830	42.51%
Summer Shoulder	$0.058180	$0.052040	-$0.006140	-10.55%
Summer off-peak	$0.055170	$0.040000	-$0.015170	-27.50%
Winter on-peak	$0.058170	$0.100000	$0.041830	71.91%
Winter off-peak	$0.043170	$0.027986	-$0.015184	-35.17%

Interruptible Power Service				
Customer Charge	$15.50	$16.00	$0.50	3.23%
Demand Charge, per kW	$3.40	$4.66	$1.26	37.17%
Energy Charge (kWhs)	$0.014800	$0.016091	$0.001291	8.72%
Base Power Supply Charge, all kWhs	$0.055491	$0.054220	-$0.001271	-2.29%
PPFAC	$0.014746	$0.000000	-$0.014746	-100.00%

Interruptible Power Service Time of Use Rates, all kWhs

(These rates would include all Delivery charges above and replace The Base Power Supply charge)

Summer on-peak	$0.071861	$0.102904	$0.031043	43.20%
Summer Shoulder	$0.059691	$0.054220	-$0.005471	-9.17%
Summer off-peak	$0.056861	$0.042904	-$0.013957	-24.55%
Winter on-peak	$0.059411	$0.102904	$0.043493	73.21%
Winter off-peak	$0.044411	$0.027772	-$0.016639	-37.47%

Lighting Dusk to Dawn				
New 30' Wood Pole (Class 6) - Overhead	$4.12	$4.35	$0.23	5.61%
New 30' Metal or Fiberglass - Overhead	$8.26	$8.72	$0.46	5.61%
Existing Wood Pole - Underground	$2.06	$2.18	$0.12	5.62%
New 30' Wood Pole (Class 6) - Underground	$6.20	$6.54	$0.35	5.62%
New 30' Metal or Fiberglass - Underground	$10.32	$10.90	$0.58	5.62%
Wattage, per Watt	$0.046577	$0.048736	$0.002159	4.63%
Lighting Base Power Supply Charge, per Watt	$0.007818	$0.007639	-$0.000179	-2.29%

Residential Service	Present	Proposed
Customer Charge	$7.50	$8.00
Energy Charge 1st 400 kWhs	$0.011255	$0.016204
Energy Charge, all additional kWhs	$0.021269	$0.026218
Base Power Supply Charge, all kWhs	$0.077993	$0.076207
PPFAC	$0.014746	$0.000000

Average Sales per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
0	$7.50	$8.00	$0.50	6.67%
50	$12.70	$12.62	($0.08)	-0.62%
100	$17.90	$17.24	($0.41)	-2.29%
200	$28.30	$26.48	($1.82)	-6.42%
400	$49.10	$44.96	($4.13)	-8.42%
600	$71.90	$65.45	($6.45)	-8.97%
800	$94.70	$85.93	($8.77)	-9.26%
1,000	$117.50	$106.42	($11.08)	-9.43%
2,000	$231.51	$208.84	($22.67)	-9.79%
2,500	$288.51	$260.06	($28.46)	-9.86%
5,000	$573.53	$516.12	($57.41)	-10.01%
10,000	$1,143.57	$1,028.24	($115.33)	-10.09%

Residential Service CARES	Present	Proposed	Discounts:	
Customer Charge	$7.50	$3.50	0-300 kWh	30.0%
Energy Charge 1st 400 kWhs	$0.011255	$0.011255	301-600 kWh	20.0%
Energy Charge, all additional kWhs	$0.021269	$0.021269	601-1000 kWh	10.0%
Base Power Supply Charge, all kWhs	$0.077993	$0.074438	1001+ kWh	$8.00
PPFAC	$0.014746	$0.000000		

Average Sales per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
0	$5.25	$2.45	($2.80)	-53.33%
50	$8.89	$5.45	($3.44)	-38.70%
100	$12.53	$8.45	($4.08)	-32.57%
200	$19.81	$14.45	($5.36)	-27.07%
400	$39.28	$30.22	($9.06)	-23.06%
600	$57.52	$45.53	($11.98)	-20.84%
800	$85.23	$68.45	($16.78)	-19.68%
1,000	$105.75	$85.68	($20.07)	-18.98%
2,000	$223.51	$182.91	($40.60)	-18.17%
2,500	$280.51	$230.76	($49.75)	-17.74%
5,000	$565.53	$470.03	($95.51)	-16.89%
10,000	$1,135.57	$948.56	($187.01)	-16.47%

Residential Service Time-of-Use Summer	Present	Proposed	Assume:	
Customer Charge	$7.50	$8.00	On Peak Usage:	16.6%
Energy Charge 1st 400 kWhs	$0.011255	$0.016204	Shoulder-Peak Usage:	15.4%
Energy Charge, all additional kWhs	$0.021269	$0.026218	Off-Peak Usage:	67.9%
Base Power Supply Charge				
On-Peak, all kWhs	$0.092183	$0.160533		
Shoulder-Peak, all kWhs	$0.081803	$0.076207		
Off-Peak, all kWhs	$0.077183	$0.055553		
PPFAC	$0.014746	$0.000000		

Average Sales per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
0	$7.50	$8.00	$0.50	6.67%
50	$12.82	$12.62	($0.20)	-1.55%
100	$18.14	$17.24	($0.90)	-4.95%
200	$28.78	$26.48	($2.30)	-7.98%
400	$50.06	$44.96	($5.09)	-10.17%
600	$73.34	$65.45	($7.89)	-10.76%
800	$96.62	$85.94	($10.68)	-11.06%
1,000	$119.90	$106.42	($13.48)	-11.24%
2,000	$236.31	$208.85	($27.46)	-11.62%
2,500	$294.51	$260.06	($34.45)	-11.70%
5,000	$585.53	$516.12	($69.40)	-11.85%
10,000	$1,167.56	$1,028.25	($139.31)	-11.93%

Residential Service Time-of-Use Winter	Present	Proposed	Assume:	
Customer Charge	$7.50	$8.00	On Peak Usage:	28.1%
Energy Charge 1st 400 kWhs	$0.011255	$0.016204		
Energy Charge, all additional kWhs	$0.021269	$0.026218	Off-Peak Usage:	71.9%
Base Power Supply Charge				
On-Peak, all kWhs	$0.080873	$0.160533		
Shoulder-Peak, all kWhs				
Off-Peak, all kWhs	$0.065873	$0.043289		
PPFAC	$0.014746	$0.000000		

Average Sales per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
0	$7.50	$8.00	$0.50	6.67%
50	$12.30	$12.62	$0.32	2.57%
100	$17.11	$17.24	$0.13	0.77%
200	$26.72	$26.48	($0.24)	-0.88%
400	$45.93	$44.96	($0.97)	-2.11%
600	$67.15	$65.45	($1.71)	-2.54%
800	$88.37	$85.93	($2.44)	-2.76%
1,000	$109.59	$106.42	($3.18)	-2.90%
2,000	$215.69	$208.84	($6.85)	-3.18%
2,500	$268.74	$260.05	($8.69)	-3.23%
5,000	$533.99	$516.10	($17.89)	-3.35%
10,000	$1,064.48	$1,028.21	($36.27)	-3.41%

Small General Service	Present	Proposed
Customer Charge	$12.00	$12.50
Energy Charge 1st 400 kWhs	$0.022449	$0.028058
Energy Charge, all additional kWhs	$0.032463	$0.038072
Base Power Supply Charge, all kWhs	$0.075738	$0.074004
PPFAC	$0.014746	$0.000000

Average Sales per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
50	$17.65	$17.60	($0.04)	-0.25%
100	$23.29	$22.71	($0.59)	-2.52%
250	$40.23	$38.02	($2.22)	-5.51%
500	$69.47	$64.53	($4.94)	-7.10%
1,000	$130.94	$120.57	($10.37)	-7.92%
2,000	$253.89	$232.65	($21.24)	-8.37%
3,500	$438.31	$400.76	($37.55)	-8.57%
5,000	$622.73	$568.87	($53.86)	-8.65%
10,000	$1,237.46	$1,129.25	($108.21)	-8.74%
30,000	$3,696.40	$3,370.77	($325.63)	-8.81%
50,000	$6,155.34	$5,612.29	($543.06)	-8.82%

Large General Service Delivery Charges	Present	Proposed		
Customer Charge	$15.50	$16.00		
Demand Charge, per kW	$10.71	$13.35	Assumes	
Energy Charge (kWhs)	$0.003254	$0.003815	Load Factor =	55.0%
Base Power Supply Charge, all kWhs	$0.067062	$0.065786		
PPFAC	$0.014746	$0.000000		

Average Sales per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
5,000	$574.18	$530.29	($43.89)	-7.64%
10,000	$1,132.87	$1,044.59	($88.28)	-7.79%
25,000	$2,808.92	$2,587.47	($221.45)	-7.88%
50,000	$5,602.35	$5,158.94	($443.41)	-7.91%
100,000	$11,189.20	$10,301.88	($887.32)	-7.93%
200,000	$22,362.89	$20,587.76	($1,775.13)	-7.94%
300,000	$33,536.59	$30,873.64	($2,662.95)	-7.94%
400,000	$44,710.29	$41,159.52	($3,550.76)	-7.94%
500,000	$55,883.98	$51,445.41	($4,438.58)	-7.94%
600,000	$67,057.68	$61,731.29	($5,326.40)	-7.94%

Large General Service TOU	Present	Proposed		
Customer Charge	$20.40	$20.90		
Demand Charge, per kW	$10.71	$13.35	Assumes	
Energy Charge (kWhs)	$0.003254	$0.003815	Load Factor =	55.0%
Base Power Supply Charge, all kWhs	$0.067062	$0.065526		
PPFAC	$0.014746	$0.000000		

Average Sales per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
5,000	$572.42	$525.58	($46.83)	-8.18%
10,000	$1,124.43	$1,030.26	($94.17)	-8.37%
25,000	$2,780.48	$2,544.31	($236.17)	-8.49%
50,000	$5,540.56	$5,067.72	($472.85)	-8.53%
100,000	$11,060.72	$10,114.53	($946.19)	-8.55%
200,000	$22,101.04	$20,208.16	($1,892.88)	-8.56%
300,000	$33,141.37	$30,301.80	($2,839.57)	-8.57%
400,000	$44,181.69	$40,395.43	($3,786.26)	-8.57%
500,000	$55,222.01	$50,489.06	($4,732.95)	-8.57%
600,000	$66,262.33	$60,582.69	($5,679.64)	-8.57%

Assumes maximum peak period demand is 5% lower than maximum demand in non-peak period.

Large Power Service (<69KV)	Present	Proposed		
Customer Charge	$365.00	$372.00		
Demand Charge, per kW	$17.90	$21.22	Assumes	
Energy Charge (kWhs)	$0.000000	($0.000000)	Load Factor =	65.0%
Base Power Supply Charge, all kWhs	$0.053260	$0.052040		
PPFAC	$0.014746	$0.000000		

Average Sales per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
300,000	$32,081	$29,401	($2,680)	-8.35%
450,000	$47,939	$43,916	($4,023)	-8.39%
650,000	$69,083	$63,268	($5,814)	-8.42%
850,000	$90,226	$82,621	($7,606)	-8.43%
950,000	$100,798	$92,297	($8,501)	-8.43%
1,500,000	$158,944	$145,517	($13,427)	-8.45%
1,750,000	$185,374	$169,708	($15,666)	-8.45%
2,000,000	$211,804	$193,899	($17,905)	-8.45%
2,500,000	$264,663	$242,280	($22,383)	-8.46%

Large Power Service (>69KV) Delivery Charges	Present	Proposed		
Customer Charge	$400.00	$407.00		
Demand Charge, per kW	$11.61	$14.93	Assumes	
Energy Charge (kWhs)	$0.000000	($0.000000)	Load Factor =	70.0%
Base Power Supply Charge, all kWhs	$0.053260	$0.052040		
PPFAC	$0.014746	$0.000000		

Average Sales per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
300,000	$27,617.85	$24,784.33	($2,834)	-10.26%
450,000	$41,226.77	$36,972.99	($4,254)	-10.32%
650,000	$59,372.00	$53,224.55	($6,147)	-10.35%
850,000	$77,517.23	$69,476.10	($8,041)	-10.37%
950,000	$86,589.85	$77,601.87	($8,988)	-10.38%
1,500,000	$136,489.23	$122,293.64	($14,196)	-10.40%
1,750,000	$159,170.77	$142,608.08	($16,563)	-10.41%
2,000,000	$181,852.31	$162,922.52	($18,930)	-10.41%
2,500,000	$227,215.39	$203,551.41	($23,664)	-10.41%

Interruptible Power Service Delivery Charges	Present	Proposed		
Customer Charge	$15.50	$16.00		
Demand Charge, per kW	$3.40	$4.66	50 Assumes	
Energy Charge (kWhs)	$0.014800	$0.016091	Load Factor =	55.0%
Base Power Supply Charge, all kWhs	$0.055491	$0.054220		
PPFAC	$0.014746	$0.000000		

Average Sales per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
10,001	$950.65	$835.35	($115.29)	-12.13%
15,000	$1,418.08	$1,244.90	($173.18)	-12.21%
20,000	$1,885.60	$1,654.54	($231.07)	-12.25%
30,000	$2,820.66	$2,473.81	($346.85)	-12.30%
50,000	$4,690.76	$4,112.34	($578.42)	-12.33%
75,000	$7,028.39	$6,160.51	($867.88)	-12.35%
100,000	$9,366.02	$8,208.68	($1,157.34)	-12.36%
125,000	$11,703.66	$10,256.85	($1,446.80)	-12.36%
150,000	$14,041.29	$12,305.03	($1,736.26)	-12.37%

	Present	Proposed	Proposed Increase $	Proposed Increase %
Lighting Dusk to Dawn Delivery Charges	Overhead Service			
New 30' Wood Pole (Class 6)	$4.12	$4.35	$0.23	5.61%
New 30' Metal or Fiberglass	$8.26	$8.72	$0.46	5.61%
	Underground Service			
Existing Wood Pole	$2.06	$2.18	$0.12	5.62%
New 30' Wood Pole (Class 6)	$6.20	$6.54	$0.35	5.62%
New 30' Metal or Fiberglass	$10.32	$10.90	$0.58	5.62%
Per Watt	$0.046577	$0.048736	$0.0022	4.63%
Lighting Base Power Supply Charge, per Watt	$0.007818	$0.00764		
PPFAC	$0.014746	$0.000000		
100 Watts - Overhead				
Existing Wood Pole	$4.67	$5.64	$0.97	20.83%
New 30' Wood Pole (Class 6)	$8.79	$9.99	$1.20	13.69%
New 30' Metal or Fiberglass	$12.92	$14.36	$1.44	11.11%
100 Watts - Underground				
Existing Wood Pole	$6.73	$7.82	$1.09	16.17%
New 30' Wood Pole (Class 6)	$10.86	$12.18	$1.32	12.15%
New 30' Metal or Fiberglass	$14.98	$16.53	$1.55	10.35%
200 Watts - Overhead				
Existing Wood Pole	$9.32	$11.27	$1.96	21.04%
New 30' Wood Pole (Class 6)	$13.44	$15.63	$2.19	16.30%
New 30' Metal or Fiberglass	$17.57	$20.00	$2.42	13.79%
200 Watts - Underground				
Existing Wood Pole	$12.94	$13.45	$0.51	3.95%
New 30' Wood Pole (Class 6)	$17.07	$17.82	$0.74	4.36%
New 30' Metal or Fiberglass	$19.63	$22.17	$2.54	12.93%
400 Watts - Overhead				
Existing Wood Pole	$21.76	$22.55	$0.79	3.64%
New 30' Wood Pole (Class 6)	$25.88	$26.90	$1.02	3.95%
New 30' Metal or Fiberglass	$30.02	$31.27	$1.26	4.18%
400 Watts - Underground				
Existing Wood Pole	$23.82	$24.73	$0.91	3.81%
New 30' Wood Pole (Class 6)	$27.95	$29.09	$1.14	4.08%
New 30' Metal or Fiberglass	$32.08	$33.45	$1.37	4.27%

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-04204A-09-0206

SURREBUTTAL

TESTIMONY

OF

KENNETH C. ROZEN

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JANUARY 15, 2010

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-09-0206

- In its Direct Testimony, Staff opposed UNS Electric, Inc.'s ("UNSE") proposed revisions to its Rules and Regulations which would 1) implement a Facilities Operation Charge, 2) specify accounting treatment of up-front payment of estimated line extension construction costs in its tariff, and 3) increase service reconnection and reestablishment fees by requiring customers whose service was disconnected to pay the applicable monthly customer charges that would have accrued had the Company continued to furnish electricity to the customer. Staff also recommended that Subsections 9.A.3 and 9.B.1.e. of the line extension tariff be revised to specify that materials costs given in line extension construction cost estimates must be itemized.

- In its Rebuttal Testimony, the Company agrees to withdraw it proposals to implement the Facilities Operation Charge, include accounting treatment of estimated construction cost payments in its tariff, and increase service reconnection and reestablishment charges.

- UNSE identifies several concerns with Staff's recommendation relating to material cost itemization in line extension agreements. Despite the Company's arguments to the contrary, Staff continues to recommend that material cost estimates in line extension agreements be itemized.

- Staff recommends that the Company clarify the intent and effect of new language in the line extension tariff related to conditions for rectifying differences in estimated and actual construction costs.

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Kenneth Rozen. My business address is 14218 North 43rd Street, Phoenix, Arizona 85032.

Q. By whom are you employed and in what capacity?

A. I am a self-employed consultant currently under contract with the Utilities Division of the Arizona Corporation Commission. My duties include evaluating various utility applications and reviewing utility tariff filings on behalf of the Utilities Division Staff ("Staff").

Q. Have you previously filed testimony in this docket?

A. Yes. I filed Direct Testimony concerning revisions that UNS Electric, Inc. ("UNSE" or "Company") proposed to make to its Rules and Regulations, as outlined in the Direct Testimony of Thomas A. McKenna.

Q. Did you review the Rebuttal Testimony that UNSE witness Mr. McKenna filed in response to your Direct Testimony?

A. Yes. I will begin by summarizing Staff's and the Company's positions as set forth in our respective Direct Testimonies. I will then summarize my understanding of Mr. McKenna's Rebuttal Testimony which was filed in response to my testimony. Finally, I will discuss Staff's position on Mr. McKenna's Rebuttal Testimony.

II. SUMMARY OF THE COMPANY'S AND STAFF'S DIRECT TESTIMONY

Q. Please summarize the Company's proposed revisions to its Rules and Regulations that remained for Commission consideration when you filed your Direct Testimony.

A. After the Commission's recent approval of certain previously-ordered revisions to UNSE's line extension tariff[1], a number of other revisions to its Rules and Regulations, which the Company proposed in its Direct Testimony in this case, remain for Commission consideration. They are as follows:

- Further revisions to the line extension tariff (Section 9), including the addition of the "Facilities Operation Charge" and language specifying in the tariff how up-front payments of estimated line extension construction costs are to be treated for accounting purposes.
- Revisions that would increase service reconnection and reestablishment fees (Sections 2, 3 and 14) by requiring customers whose service was disconnected to pay the monthly customer charges that would have accrued had the Company continued to furnish electricity to the customer.
- Revisions adding time frames for rectifying under- and over-billings resulting from meter and meter reading errors (Section 11); and
- Numerous technical and clarifying revisions throughout the Rules and Regulations.

Q. Please summarize Staff's recommendations regarding these proposals and any other matters relating to UNSE's Rules and Regulations?

A. Staff has no objections to UNSE's proposed revisions that would add timeframes for rectifying meter and meter reading errors or to the numerous technical and clarifying changes. For reasons explained in my Direct Testimony, however, Staff opposes UNSE's proposals to: 1) implement a Facilities Operation Charge, 2) specify in the line extension

[1] The Commission approved UNSE's line extension tariff, as revised to eliminate the free-footage allowance, in Decision No. 71285 dated October 7, 2009.

tariff the accounting treatment for the proceeds from up-front payments of estimated construction costs, and, 3) increase service reconnection and reestablishment fees by requiring customers whose service was disconnected to pay the applicable monthly customer charges that would have accrued had the Company continued to furnish electricity to the customer. Apart from UNSE's proposed revisions, Staff is further recommending that Subsections 9.A.3 and 9.B.1.e. of the line extension tariff be revised to specify that materials costs given in line extension construction cost estimates must be itemized.

III. UNSE'S REBUTTAL TESTIMONY

Q. Please summarize Mr. McKenna's Rebuttal Testimony.

A. Mr. McKenna's Rebuttal Testimony indicates that UNSE: 1) withdraws its request to implement a Facilities Operation Charge, 2) agrees to remove proposed language in its line extension tariff that would specify accounting treatment for up-front payments received by the Company for estimated line extension construction costs and 3) agrees to delete the proposed revisions that would have allowed the Company to collect, in addition to the service reestablishment and reconnection fees. However, Mr. McKenna has a number of concerns about Staff's recommendation that Subsection 9.B.1.e of the line extension tariff be revised to specify that material costs listed in construction cost estimates included in line extension agreements should be itemized. Finally, Mr. McKenna's Rebuttal Testimony includes a number of additional requests for technical and typographical revisions to various sections of UNSE's Rules and Regulations.

Q. On December 11, 2009, UNSE filed Exhibit TAM-5, which UNSE states reflects UNSE's proposed changes to its current Commission-approved Rules and Regulations as revised by Mr. McKenna's Rebuttal Testimony. Have you reviewed Exhibit TAM-5?

A. Yes.

Q. Is Exhibit TAM-5 consistent with Mr. McKenna's Rebuttal Testimony?

A. Yes.

Q. Does Staff have any concerns with any of the additional technical and typographical revisions that Mr. McKenna proposes in his Rebuttal Testimony?

A. No.

Q. What are UNSE's concerns with Staff's recommendation to itemize material costs in the construction cost estimates that are contained in line extension agreements?

A. Mr. McKenna states that the Company:

1. Does not believe that itemizing material costs will enhance Applicants' understanding of cost estimates in part because most customers are unfamiliar with power line engineering and construction materials (He does not identify other factors which may contribute to UNSE's belief that material cost itemization would not help Applicant's understand line extension construction cost estimates.);
2. Cannot sacrifice safe and reliable construction and operation in deference to the Applicant's interest in minimizing extension costs, even if materials were itemized; and;

3. Believes that the line extension description and sketch already required by Commission rule[2] and the parallel provision in UNSE's Rules and Regulations are sufficient for the Applicant to understand what the Company requires and why.

IV. STAFF'S SURREBUTTAL TESTIMONY

Q. Please respond to UNSE's concerns regarding Staff's recommendation to itemize materials costs in the construction cost estimates contained in line extension agreements.

A. The line extension description and sketch may provide sufficient basis for an Applicant to understand what is being required and why, but neither a sketch nor a description that does not identify the costs of the various construction items comprising the facility provides the Applicant with an adequate basis for understanding line extension costs. Regardless of the extent to which any one Applicant chooses to consider it, Staff believes UNSE should provide all Applicants with a sound basis for understanding extension costs, including itemized materials costs, both as estimated in the Agreement and in the context of any adjustments necessitated by the results of the Company's comparison between the estimated and actual costs[3].

Staff agrees that the Company must not sacrifice reliability and safety in deference to an Applicant's interest in minimizing costs. It is difficult to understand, however, how requiring the Company to itemize costs would compromise reliability and safety. Further, the Company's concern on this issue seems to presume that Applicants' proclivity to dispute the Company's cost estimates would increase if estimated materials costs were itemized. This presumption remains unsubstantiated. Finally, Staff disagrees with UNSE's view that itemizing estimated materials costs would not enhance Applicant's

[2] A.A.C. R14-2-207.B.1.d

[3] For rectifying estimated and actual costs, see proposed Exhibit TAM-5, relined version, page 31, Subsection 9.D.1.

understanding of cost estimates because most customers are unfamiliar with power line construction materials.

For example, the table at the top of UNSE's response to Data Request STF 17.2[4] lists twelve "Construction Units." Among these, Staff suspects that many if not most customers would know that "Transformer" is a piece of equipment needed to reduce voltage, "Primary Conductor" refers to wires used to transmit electricity, and "Guys" are wires or cables used to support or brace structures, such as poles, which are used to suspend conductor overhead. Although many if not most customers would be unfamiliar with "Tangent," "Angle," and "Dead End," many might correctly surmise that these terms distinguish different kinds of towers and poles, based on their position in and the configuration of the line extension. Regardless of any one Applicant's familiarity with the Construction Units listed in the table, however, Staff fails to see how providing the Applicant with the "Unit Cost" and "# Reqd." for each could *not* enhance the Applicant's understanding of the estimated Total Material cost, and by extension, the Line Extension Cost Estimate, of which Total Material Cost is a significant component.

Q Mr. McKenna notes that the line extension agreement requirements in UNSE's rules and regulations are directly from A.A.C. R14-2-207. Would the application of that rule in any way limit the Commission's ability to require a company to expand information in line extension agreements beyond what is required by R14-2-207.B.1?

A. No. Both A.A.C. R14-2-207.B.1 and Subsection 9.B.1 state "Each line extension agreement [must/shall], *at a minimum*, include the following information:"(emphasis added) Staff is of the opinion that this language allows the Commission to expand the requirements when it finds that such expansion is warranted.

[4] Exhibit KCR-2 to Rozen Direct Testimony

Q. After considering Mr. McKenna's Rebuttal Testimony, does Staff have any reason to change its recommendation that the Company revise Subsection 9.B.1.e to require that material costs be itemized in construction cost estimates that are included in line extension agreements.

A. No.

Q. Are there any other matters relating to UNSE's Rules and Regulations that you would like to address?

A. Yes, there are two such matters, both relating to Section 9, the line extension tariff.

Q. What is the first of these?

A. In the revised line extension tariff that UNSE filed in Docket E-04204A-06-0783, as ordered in Commission Decision No. 71285, Subsection 9.D.1.b, which applies to overhead extensions to Large Light and Power Customers, contains the following provision:

> "Upon completion of construction the Company will compare actual cost to the estimated cost and any difference will be either billed or refunded to the Customer."

UNSE's proposed revision to its line extension tariff shown in TAM-2 and TAM-5 retains this same language, but moves it to the very beginning of Subsection 9.D ("Conditions Governing Extensions of Electric Distribution and Service Lines") and adds new language as follows:

"- except if the difference is less than \$500. If the difference is less than \$500, the amount may be billed or refunded according to the specific extension agreement with the customer."

Q. Does Staff have any concerns with these changes?

A. Staff supports moving the language that provides for rectifying differences between estimated and actual costs to the beginning of Subsection 9.D because it has the effect of applying the rectification provision to all of the subsections comprising Subsection 9.D. However, Staff is concerned that the intent and effect of the new language is unclear.

Q. What is Staff's recommendation regarding the new language?

A. Staff recommends that the Company clarify the intent and effect of the new language in its Rejoinder Testimony. Staff will respond to the clarification at the hearing.

Q. What is the second matter regarding the line extension tariff that you would like to address?

A. The revised line extension tariff that UNSE filed in Docket E-04204A-06-0783, as well as the revisions proposed in TAM-5, eliminate the free footage allowance as the Commission ordered in Decision No. 70360. However, A.A.C. R14-2-207.C continues to require that each line extension shall include a maximum footage or equipment allowance to be provided by the utility at no charge. Therefore, UNSE's current and proposed line extension tariffs conflict with provisions of R14-2-207, including Subsection A.1, which states "each utility shall file, in Docket Control, for Commission approval, a line extension tariff which incorporates the provisions of this rule."

Q. Does Staff have a recommendation regarding a resolution to this conflict?

A. Yes. Neither the Decision (No. 70360) in which the Commission ordered the elimination of the free footage allowance, nor the Decision (No. 71285) in which the Commission approved the responsive revision to UNSE's line extension tariff, granted UNSE a waiver to A.A.C. R14-2-207.C. Therefore, Staff recommends that the Commission consider granting such a waiver in this proceeding.

V. SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. Staff's recommendations are as follows:

1. Staff maintains its recommendation that Subsection 9.B.1.e of UNSE's line extension tariff be revised to require that the materials costs given in construction cost estimates contained in line extension agreements be itemized.

2. Staff recommends that, in its Rejoinder Testimony, the Company clarify the intent and effect of the new language regarding rectifying differences between estimated and actual line extension construction costs.

3. Staff recommends that the Commission consider granting UNSE a waiver to A.A.C. R14-2-207.C in this proceeding.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes, it does.